# DETERMINATION OF COMPLIANCE EVALUATION

**Turlock Irrigation District - Walnut Energy Center Project**
**California Energy Commission**
**Application for Certification Docket #: 02-AFC-4**

| | |
|---|---|
| **Facility Name:** | Turlock Irrigation District |
| **Mailing Address:** | P.O. Box 949<br>Turlock, CA 95381-0949 |
| **Contact Name:** | Randy C. Baysinger, Assistant General Manager |
| **Telephone:** | (209) 883-8550 |
| **Fax:** | (209) 656-2146 |
| **E-Mail:** | rcbaysinger@tid.org |
| **Other Contact:** | Jeffrey Adkins |
| **Telephone:** | (916) 444-6666 |
| **Fax:** | (916) 444-8373 |
| **E-Mail:** | JAdkins@sierraresearch.com |
| **Other Contact:** | Gary Rubenstein |
| **Telephone:** | (916) 444-6666 |
| **Fax:** | (916) 444-8373 |
| **E-Mail:** | GRubenstein@sierraresearch.com |
| **Engineer:** | Kai Chan, Air Quality Engineer |
| **Lead Engineer:** | Rupi Gill, Supervising Air Quality Engineer |
| **Date:** | March 26, 2003 |
| **Project #:** | N1021521 |
| **Application #'s:** | N-2246-1-4, N-2246-2-4, N-2246-3-0, N-2246-4-0,<br>N-2246-5-0, & N-2246-6-0 |
| **Submitted:** | November 22, 2002 |
| **Deemed Complete:** | December 11, 2002 |
| **Preliminary DOC:** | April 24, 2003 |
| **Final DOC:** | |

## Table of Contents

## I. PROPOSAL:

Turlock Irrigation District – Walnut Energy Center (hereinafter referred to as "WEC") is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of an electrical power generation facility. The WEC will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG). Also proposed is a condensing steam turbine generator, a 5-cell mechanical draft cooling tower, a 300 hp diesel-fired emergency IC engine powering a fire pump and associated facilities. The plant will have a nominal rating of 250 MW (at average annual ambient conditions).

WEC is also proposing to limit the annual $PM_{10}$ emission rate from the two existing 25.8 MW peak-load, simple-cycle combustion turbine power generating units to 7,016 lb/year (each) to offset the $PM_{10}$ emission increases due to this proposed project. In addition, the applicant is proposing to maintain the current combined daily $PM_{10}$ emission rate from the two existing combustion turbine generators to 150 lb/day.

The Turlock Irrigation District – Walnut Energy Center is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

## II. APPLICABLE RULES:

| | |
|---|---|
| **Rule 1080** | Stack Monitoring (12/17/92) |
| **Rule 1081** | Source Sampling (12/16/93) |
| **Rule 1100** | Equipment Breakdown (12/17/92) |
| **Rule 2010** | Permits Required (12/17/92) |
| **Rule 2201** | New and Modified Stationary Source Review Rule (4/25/02)[1] |
| **Rule 2520** | Federally Mandated Operating Permits (6/21/01) |
| **Rule 2540** | Acid Rain Program (11/13/97) |
| **Rule 2550** | Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98) |
| **Rule 4001** | NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines (4/14/99) |
| **Rule 4002** | National Emissions Standards for Hazardous Air Pollutants (5/18/00) |
| **Rule 4101** | Visible Emissions (11/15/01) |

[1] District Rule 2201 was last amended on December 19, 2002. Since this application was deemed complete prior to December 19, 2002, then District Rule 2201 effective prior to December 19, 2002 will be utilized to evaluate this project.

## II. APPLICABLE RULES (Continued):

**Rule 4102** Nuisance (12/17/92)
**Rule 4201** Particulate Matter Concentration (12/17/92)
**Rule 4202** Particulate Matter Emission Rate (12/17/92)
**Rule 4301** Fuel Burning Equipment (12/17/92)
**Rule 4701** Internal Combustion Engines (12/19/02)
**Rule 4703** Stationary Gas Turbines (4/25/02)
**Rule 4801** Sulfur Compounds (12/17/92)
**Rule 7012** Hexavalent Chromium - Cooling Towers (12/17/92)
**Rule 8011** General Requirements (11/15/01)
**Rule 8021** Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (11/15/01)
**Rule 8031** Bulk Materials (11/15/01)
**Rule 8041** Carryout and Trackout (11/15/01)
**Rule 8051** Open Areas (11/15/01)
**Rule 8061** Paved and Unpaved Roads (11/15/01)
**Rule 8071** Unpaved Vehicle/Equipment Traffic Areas (11/15/01)
**Rule 8081** Agricultural Sources (11/15/01)
**California Environmental Quality Act (CEQA)**
**California Health & Safety Code (CH&S)**, Sections 41700 (Health Risk Analysis), 42301.6 (School Notice), and 44300 (Air Toxic “Hot Spots”)

## III. PROJECT LOCATION:

The proposed WEC will be located on an 18-acre site within an 69-acre parcel located about 2,000 feet southeast of the intersection of West Main street and Washington Road within the City of Turlock in Stanislaus County, California. The proposed location is not within 1,000' of a K-12 school.

Section 18, Township 5 South, Range 10 East. (See Attachment B)

## IV. PROCESS DESCRIPTION:

### Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7EA units combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low $NO_X$ combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 84 MW of electricity. The plant will be a “combined-cycle plant,” since the gas turbine and a steam turbine both turn electrical generators and produce power. Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 100 MW, which turns another electrical generator.

## IV. PROCESS DESCRIPTION (Continued):

The facility has proposed an operating scenario of 7,280 hours of full load operation per year with 296 total startups and shutdown equally divided among the calendar year as shown in the table below:

| N-2246-3-0 and N-2246-4-0<br>Walnut Energy Center - Operating Scenario (per unit) | | | | | |
|---|---|---|---|---|---|
| | **Quarter 1** | **Quarter 2** | **Quarter 3** | **Quarter 4** | **Annual** |
| Number of Startup/Shutdown Hours | 74 | 74 | 74 | 74 | 296 |
| Number of Full Load Hours | 1,820 | 1,820 | 1,820 | 1,820 | 7,280 |
| Total Hours | 1,894 | 1,894 | 1,894 | 1,894 | 7,576 |

The CTGs will utilize Dry Low $NO_X$ (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

$NO_X$: 2.0 ppmvd @ 15% $O_2$ (over a 1 hour rolling average).
VOC: 1.4 ppmvd @ 15% $O_2$ (over a 3 hour rolling average).
CO: 4.0 ppmvd @ 15% $O_2$ (over a 3 hour rolling average).
$SO_X$: 0.0010 lb/MMBtu (Based on mass balance with 0.36 gr-S/100 as proposed by the applicant)
$PM_{10}$: 0.0067 lb/MMBtu (7.0 lb/hr)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record $NO_X$, CO, and $O_2$ concentrations in the exhaust gas for each CTG.

**Heat Recovery Steam Generators (HRSGs)**

The HRSGs provide for the transfer of heat from the exhaust gases of the CTGs to the feedwater, which is turned into steam. The HRSGs will be three-pressure, natural circulation units equipped with inlet and outlet ductwork, insulation, lagging, and separate exhaust stacks.

Major components of each HRSG include a feedwater preheater, low pressure (LP) evaporator, LP drum, LP superheaters, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters and reheaters, high pressure (HP) economizer, HP drum, HP evaporator, and HP superheaters. The feedwater preheater receives condensate from the condenser hot well via the condensate pumps. The feedwater preheater is the final heat transfer section to receive heat from the combustion gases prior to their exhausting to the atmosphere.

## IV. PROCESS DESCRIPTION (Continued):

From the feedwater preheater, the condensate is directed to the LP drum where it is available to generate LP steam and supply condensate to the boiler feed pumps. The boiler feed pumps draw suction from the LP drum and provide additional pressure to serve the separate IP and HP sections of the HRSG.

Feedwater from the boiler feed pumps is sent to the HP section of the HRSG. High-pressure feedwater flows through the HP economizer where it is preheated prior to entering the HP steam drum. Within the HP steam drum, a saturated liquid state will be maintained. The saturated water will flow through downcomers from the HP steam drum to the inlet headers at the bottom of the HP evaporator. Saturated steam will form in the tubes as energy from the combustion turbine exhaust gas is absorbed. The HP saturated liquid/vapor mixture will then return to the steam drum where the two phases will be separated by the steam separators in the drum. The saturated water will return to the HP evaporator, while the vapor continues on to the HP superheater. Within the HP superheater, the temperature of the HP steam will be increased above its saturation temperature, or “superheated” prior to being admitted to the HP section of the steam turbine.

Feedwater will also be sent to the IP section of the HRSG by an interstage bleed from the boiler feed pumps. Similar to the HP section, feedwater will be preheated in the IP economizer and steam will be generated in the IP evaporator. The saturated IP steam will pass through an IP superheater and then be mixed with “cold reheat” steam from the discharge of the steam turbine HP section. The blended steam will then pass through two additional IP superheaters, reheating the steam to a superheated state. The “hot reheat” steam will then be admitted to the steam turbine IP section.

Condensate will be preheated by the feedwater preheater prior to entering the LP steam drum. Similar to the HP and IP sections, steam will be generated in the LP evaporator and superheated in the LP superheater. The superheated LP steam will then be admitted to the LP section of the steam turbine along with the steam exhausting from the steam turbine IP section.

### Steam Turbine Generator

The steam turbine system consists of a 100 MW nominally rated condensing steam turbine generator (STG) with reheat, gland steam system, lubricating oil system, hydraulic control system, and steam admission/induction valving. Steam from the HRSG HP, IP, and LP superheaters enters the associated steam turbine sections through the inlet steam system. The steam expands through multiple stages of the turbine, driving the generator. On exiting the turbine, the steam is directed into the surface condenser.

## IV. PROCESS DESCRIPTION (Continued):

### Cooling Tower

One mechanical-draft evaporative cooling tower will be used to provide cooling water for the steam turbine surface condenser and other cooling loads. The cooling tower will consist of 5 cells and have a design water flow rate of 68,500 gallons per minute (gpm). The cooling tower will be equipped with a high efficiency mist eliminator to minimize cooling tower drift and the resultant $PM_{10}$ emissions. The $PM_{10}$ emissions are due to total dissolved solids (TDS) in the cooling water. No chromium containing compounds will be added to the cooling water.

### Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. A fire pump controller will be provided for the back-up fire pump. During fire conditions, the diesel-powered pump will operate if the electric motor-driven main fire pump fails to operate. The diesel-fired engine will be rated at 300 horsepower. The engine will be limited to no greater than 100 hours per year of non-emergency operation in accordance with District rules.

### Simple-Cycle Combustion Turbine Generators (Existing Units)

Each General Electric Frame 5 simple-cycle combustion turbine generator (SCTG) may be fired on natural gas or fuel oil #2 and will be equipped with a water injection system. Each SCTG will drive an electrical generator to produce approximately 25.8 MW of electricity. These units are peak load units, which only operate during summer peak loads as needed when other electric resources become unavailable or when emergency energy supplies are needed. Currently, each unit's operation is limited by permit condition to less than 877 hours/year.

## V. EQUIPMENT LISTING:

**N-2246-3-0:** 84 MW nominally rated combined-cycle power generating system #1 consisting of a 1,047 MMBtu/hr General Electric Frame 7EA natural gas-fired combustion turbine generator with Dry Low $NO_X$ combustor, an inlet air filtration and evaporative cooling system, a selective catalytic reduction (SCR) system, an oxidation catalyst, heat recovery steam generator #1 (HRSG) and a 100 MW nominally rated steam turbine shared with N-2246-4.

## V. EQUIPMENT LISTING (Continued):

**N-2246-4-0:** 84 MW nominally rated combined-cycle power generating system #2 consisting of a 1,047 MMBtu/hr General Electric Frame 7EA natural gas-fired turbine generator with Dry Low $NO_X$ combustor, an inlet air filtration and evaporative cooling system, a selective catalytic reduction (SCR) system, an oxidation catalyst, heat recovery steam generator #2 (HRSG) and a 100 MW nominally rated steam turbine shared with N-2246-3.

**N-2246-5-0:** 68,500 gpm mechanical draft cooling tower with 5 cells served by a high efficiency drift eliminator.

**N-2246-6-0:** 300 hp John Deere Company Model JW6H-UF40 diesel-fired emergency IC engine powering a fire pump.

**N-2246-1-4:** 25.8 MW nominally rated simple-cycle peak-demand power generating system #1 consisting of a 325 MMBtu/hr General Electric Model PG 5361 Frame 5 natural gas/fuel oil #2 fired turbine generator with water injection.

**N-2246-2-4:** 25.8 MW nominally rated simple-cycle peak-demand power generating system #2 consisting of a 325 MMBtu/hr General Electric Model PG 5361 Frame 5 natural gas/fuel oil #2 fired turbine generator with water injection.

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

### i. N-2246-3-0 & N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):

Each CTG will be equipped with a Dry Low $NO_X$ combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low $NO_X$ combustors and a SCR system with ammonia injection can achieve a $NO_X$ emission rate of 2.0 ppmvd @ 15% $O_2$. CO emissions of 4 ppmvd @ 15% $O_2$ have been demonstrated with the use of an oxidation catalyst [(2)]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of $\leq$ 2 ppmvd @ 15% $O_2$.

Emissions from natural gas-fired turbines include $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$.

$NO_X$ is the major pollutant of concern when combusting natural gas. Virtually all gas turbine $NO_X$ emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable $NO_2$ molecule. There are two mechanisms by which $NO_X$ is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal $NO_X$ and prompt $NO_X$), and 2) the conversion of nitrogen chemically bound in the fuel (fuel $NO_X$).

[2] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION (Continued):

Thermal $NO_X$ is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt $NO_X$, a form of thermal $NO_X$, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form $NO_X$. Prompt $NO_X$ is formed in both fuel-rich flame zones and dry low $NO_X$ (DLN) combustion zones. The contribution of prompt $NO_X$ to overall $NO_X$ emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal $NO_X$ emissions in DLN combustors. For this reason prompt $NO_X$ becomes an important consideration for DLN combustor designs, and establishes a minimum $NO_X$ level attainable in lean mixtures.

Fuel $NO_X$ is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as $N_2$ in some natural gas, does not contribute significantly to fuel $NO_X$ formation. With excess air, the degree of fuel $NO_X$ formation is primarily a function of the nitrogen content in the fuel. When compared to thermal $NO_X$, fuel $NO_X$ is not currently a major contributor to overall $NO_X$ emissions from stationary gas turbines firing natural gas.

The level of $NO_X$ formation in a gas turbine, and hence the $NO_X$ emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of $NO_X$ generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of $NO_X$. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal $NO_X$ formation. Thermal $NO_X$ formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects $NO_X$ formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal $NO_X$ production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal $NO_X$ formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum $NO_X$ formation during combustion. This is known as dry low $NO_X$ (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce $NO_X$ emissions by injecting ammonia ($NH_3$) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, $NH_3$, and $O_2$ react on the surface of the catalyst to form molecular nitrogen ($N_2$) and $H_2O$. SCR is capable of over 90 percent $NO_X$ reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause $NO_X$ and $NH_3$ to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% $O_2$.

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION (Continued):

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit $NO_X$ formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide ($CO_2$).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

### ii. N-2246-5-0 (5-Cell Cooling Tower):

The cooling towers are a source of $PM_{10}$ emissions. $PM_{10}$ emissions are due to the total dissolved solids (TDS), mostly salts, in the cooling water. In the cooling process, some of the cooling water (and TDS) is carried out. This is referred to as drift. Some portion of the drift dries in the air before settling to ground, and its TDS content can thereby become airborne PM. The applicant has conservatively assumed that all drift will remain suspended in the air and will dry to $PM_{10}$. This approach overstates $PM_{10}$ emissions.

Cooling water drift is controlled by using drift eliminators in each of the cooling tower cells. These drift eliminators act as a coalescer for the evolved cooling water to collect on and drop back into the process stream. The proposed drift eliminators have a drift rate of 0.0005%, i.e. 0.0005% of the cooling water circulated is emitted.

### iii. N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):

The diesel-fired emergency IC engine will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on low (0.05%) sulfur diesel.

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION (Continued):

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[3]

The turbocharger reduces the $NO_X$ emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

Retarding the fuel injection timing by at least 4° from standard or having the fuel injection timing advanced to no greater than 16° before top dead center (BTDC) lowers the peak combustion temperature and reduces the formation of thermal $NO_x$. $NO_x$ emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.05% by weight sulfur maximum) diesel fuel reduces $SO_X$ emissions by approximately 90% and $PM_{10}$ emissions by approximately 25% from standard diesel fuel.

**iv. N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

Each SCTG is equipped with an inlet air filtration system and a water injection system. The water injection system will allow each turbine to achieve NOx emissions less than 25 ppmvd @ 3% $O_2$ (when fired on natural gas) and less than 42 ppmvd @ 15% $O_2$ (when fired on fuel oil #2).

NOx formation is proportional to the heat of combustion. Water injection into the combustion zone has the affect of reducing NOx formation by reducing the flame temperature.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

## VII. GENERAL CALCULATIONS:

### A. Assumptions

**i. N-2246-3-0 & N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

1. Maximum emissions for each CTG during the commissioning period are estimated assuming 72 hours of operation at no load, 144 hours of operation at 50% load, 48 hours of operation at full load with SCR not operational, and 24 hours of operation at full load with partial operation of the SCR.

[3] From "Non-catalytic $NO_x$ Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

## VII. GENERAL CALCULATIONS (Continued):

2. The maximum hourly and daily emissions during the commissioning period for the two turbines operating simultaneously will occur when one turbine is in commissioning mode and the other turbine is operating at full load and maximum permitted emission rates.

3. The commissioning period for each CTG will not exceed 288 hours and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.

4. BACT emission concentration limits of 2.0 ppmvd @ 15% $O_2$, 4.0 ppmvd @ 15% $O_2$, and 1.4 ppmvd @ 15% $O_2$ are proposed for $NO_x$, CO, and VOC, respectively, at all operating loads (except during start-ups and shutdowns).

5. The applicant proposes $NO_X$, CO and VOC mass emission rates of 7.6 lb/hr, 9.3 lb/hr and 1.8 lb/hr, respectively, at 100% load and 32 °F (worst case ambient temperature).

6. The applicant proposes for the CTGs a $PM_{10}$ mass emission rate of 7.0 lb/hr for each CTG, at 100% load and 32 °F (worst case ambient temperature), based on the vendor's guarantee for both the filterable and condensable portions of $PM_{10}$.

7. A $SO_X$ emissions rate of 1.0 lb/hr was calculated using the CTGs maximum heat input of 1,047 MMBtu/hr (@ 100% load and 32 °F) and by performing a mass balance assuming 1,000 Btu/scf (hhv) for natural gas, and a natural gas sulfur content of 0.36 gr S/100 scf.

   (0.36 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb $SO_X$/32 ~~lb S~~ x 1 ~~scf~~/1000 ~~Btu~~ x $10^6$ ~~Btu~~/MMBtu)
   = 0.0010 lb/MMBtu

8. The maximum hourly emissions for the two turbines operating simultaneously will occur when one turbine is in start-up mode and the other turbine is operating at full load.

9. Maximum daily emissions for each CTG for $NO_X$, CO, and VOC are estimated assuming 5 hours operating in cold startup mode and 19 hours operating at full load.

10. Maximum daily emissions for each CTG for $PM_{10}$, $SO_X$, and $NH_3$ are estimated assuming 24 hours operating at 100% load @ 32°F.

11. Maximum combined NOx quarterly emission limit from the two new CTGs of 35,000 pounds/quarter and maximum combined NOx annual emissions from the two new CTGs of 140,000 pounds/year.

12. Maximum annual emissions for each CTG for CO and VOC are estimated assuming 296 hours operating in startup/shutdown mode and 7,280 hours operating at 100% load @ 61°F.

## VII. GENERAL CALCULATIONS (Continued):

13. Maximum annual emissions for each CTG for $PM_{10}$, $SO_X$, and $NH_3$ are estimated assuming 7,576 hours operating at 100% load @ 61°F.

14. Quarterly emissions are based on the following hypothetical operating schedule:

| N-2246-3-0 and N-2246-4-0<br>Walnut Energy Center - Operating Scenario (per unit)<br>(Repeated from page 3) | | | | | |
|---|---|---|---|---|---|
| | **Quarter 1** | **Quarter 2** | **Quarter 3** | **Quarter 4** | **Annual** |
| Number of Startup/Shutdown Hours | 74 | 74 | 74 | 74 | 296 |
| Number of 100% Load Hours | 1,820 | 1,820 | 1,820 | 1,820 | 7,280 |
| Total Hours | 1,894 | 1,894 | 1,894 | 1,894 | 7,576 |

### ii. N-2246-5-0 (5-Cell Cooling Tower):

1. Density of water is 8.34 lb/gal.

2. Total dissolved solids (TDS) is predominately sodium chloride.

3. Cooling tower drift eliminator has a drift rate of 0.0005% (0.0005% of circulated water is emitted).

4. Maximum daily $PM_{10}$ emissions from the cooling tower will be estimated assuming 24 hours operating at maximum output.

5. Maximum annual $PM_{10}$ emissions from the cooling tower will be estimated assuming 8,760 hours operating at maximum output.

### iii. N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):

| | |
|---|---|
| Operating Schedule: | 24 hours/day maximum emergency use<br>100 hours/year maximum non-emergency use |
| Density of Diesel Fuel: | 7.1 lb/gal (AP-42, Appendix A) |
| EPA F-factor (60 °F): | 9,051 dscf/MMBtu |
| Fuel Heating Value: | 140,000 Btu/gal (AP-42, Table 3.3-1) |
| Fuel Consumption Rate: | 14.5 gal/hr @ 100% load |
| Sulfur Content of Fuel: | 0.05% by weight |

**VII. GENERAL CALCULATIONS (Continued):**

**iv. N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

1. The molar specific volume (MSV) of any gas at 60°F is 379.5 scf/lb-mol.
2. The molecular weight (MW) of NOx (as $NO_2$) is 46 lb/lb-mol.
3. The molecular weight (MW) of CO is 28 lb/lb-mol.
4. The F-factor for natural gas is 8,578 dscf/MMBtu (@ 60°F).
5. The F-factor for fuel oil #2 is 9,051 dscf/MMBtu (@60°F).
6. The maximum heat input rate into each turbine is 325 MMBtu/hr.
7. The worst-case daily and annual emission rates will be estimated assuming operation on fuel oil #2 for 24 hours/day and 877 hours/year.
8. No proposed changes to the current NOx, CO, VOC, and SOx emissions limits due to the proposed project.
9. No proposed change to the current combined NOx emission limit of 1,020 pounds/day and 25,551 pounds/quarter for these two CTGs.
10. No proposed change to the current combined daily $PM_{10}$ emission limit of 150 pounds/day from these two CTGs.
11. Proposed annual $PM_{10}$ emission limit of 7,016 lb/yr for each CTG.

**B. <u>Emission Factors</u>**

**i. N-2246-3-0 & N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

| Commissioning Period Emissions (Per Turbine in lb/hr) | | | | | |
|---|---|---|---|---|---|
| Operating Mode | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ |
| No Load | 108.82 | 180.0 | 17.0 | 7.0 | 0.30 |
| 50% Load | 56.23 | 210.0 | 16.0 | 7.0 | 0.62 |
| Full Load – No SCR | 51.40 | 20.87 | 1.67 | 7.0 | 0.94 |
| Full Load – Partial SCR | 29.13 | 8.34 | 1.67 | 7.0 | 0.94 |

The maximum air contaminant mass emission rates (lb/hr), concentrations (ppmvd @ 15% $O_2$), and startup and shutdown emissions rates (lb/hr) estimated by the manufacturer (see Attachment D for manufacturer's emissions data) for the proposed CTGs are summarized below:

## VII. GENERAL CALCULATIONS (Continued):

| Maximum Emission Rates and Concentrations @ 100% Load & 32°F | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| Mass Emission Rates (per turbine in lb/hr) | 7.59 | 9.25 | 1.84 | 7.0 | 1.05 | 14.06 |
| ppmvd @ 15% $O_2$ limits | 2.0 | 4.0 | 1.4 | -- | 0.2 | 10.0 |

| Maximum Emission Rates and Concentrations @ 100% Load & 61°F | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| Mass Emission Rates (per turbine in lb/hr) | 7.18 | 8.74 | 1.74 | 7.0 | 0.99 | 13.28 |
| ppmvd @ 15% $O_2$ limits | 2.0 | 4.0 | 1.4 | -- | 0.2 | 10.0 |

| Startup and Shutdown Emissions | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ |
| Mass Emission Rate (per turbine in lb/hr) | 119 | 129 | 16 | N/A[4] | N/A[4] |
| Mass Emission Rate (per turbine in lb/start[5]) | 300 | 383 | 48 | N/A[4] | N/A[4] |

**ii. N-2246-5-0 (5-Cell Cooling Tower)**

1. Maximum cooling tower water circulation rate of 68,500 gal/min (per Applicant).
2. Cooling water drift total dissolved solids (TDS) of 7,500 mg/L (per Applicant).
3. Proposed $PM_{10}$ emission rate of 1.3 lb/hour (per Applicant).

**iii. N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

Emission factors for the combustion of diesel fuel from the I.C. engine for NOx, CO, VOC, and $PM_{10}$ emissions will be based on emission factors from the engine manufacturer. SOx emission factor will be determined using mass balance with a maximum sulfur content of 0.05% by weight.

$$
\begin{aligned}
EF_{SOx} &= 0.0005 \text{ lbm S/lbm fuel} \times 7.1 \text{ lbm fuel/gal fuel} \times 453.6 \text{ g/lbm} \\
&\quad \times 2 \text{ lbm } SO_2 \text{ exhaust/1 lbm S in fuel} \times 14.5 \text{ gal/hr} \times 1/300 \text{ hp} \\
&= 0.16 \text{ g/hp-hr}
\end{aligned}
$$

[4] $PM_{10}$ and $SO_X$ emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.
[5] Maximum emissions based on five hours per cold start or 2 hours required per hot start.

| Diesel-fired IC Engine Emission Factors | | |
|---|---|---|
| Pollutant | g/hp·hr | Source |
| NOx | 5.20 | Engine Manufacturer |
| CO | 0.27 | Engine Manufacturer |
| VOC | 0.15 | Engine Manufacturer |
| $PM_{10}$ | 0.09 | Engine Manufacturer |
| SOx | 0.16 | Mass Balance Equation Above |

**iv. N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

The emission factors for the combustion of natural gas and fuel oil #2 for NOx, CO, and $PM_{10}$ emissions will be based on the emission rates as proposed by the applicant. The emission factor for the combustion of natural gas and fuel oil #2 for VOC emissions is based on the emission rate data from the original application review for these permit units. The emission factor for SOx, when burning natural gas is based on mass balance with 1.0 gr-S/100 $ft^3$ per District Policy APR 1720. The emission factor for SOx when burning fuel oil #2 is based on a liquid fuel sulfur content of less than 0.05% by weight as required by District Rule 4703, Section 3.12. Therefore, the $SO_x$ emission rate for fuel oil #2 combustion is estimated as follows:

$$
\begin{aligned}
EF_{SOx\ (Fuel\ Oil\ \#2)} &= (325\times10^6\ \text{Btu/hr}) \times (\text{gal-fuel}/140{,}000\ \text{Btu}) \times (7.1\ \text{lb-fuel/gal-fuel}) \\
&\quad \times (0.05\ \text{lb-S}/100\ \text{lb-fuel}) \times (64\ \text{lb-}SO_2/32\ \text{lb-S}) \\
&= 16.48\ \text{lb-}SO_2\text{/hr.}
\end{aligned}
$$

| Pollutant | Emission Factor (ppmvd @ 15% $O_2$, lb/MMBtu, or lb/hr) |
|---|---|
| $NO_x$ | 25.0 ppmvd (natural gas) |
| | 42.0 ppmvd and 51 lb/hr (fuel oil #2) |
| VOC | 15 lb/hr (both natural gas and fuel oil #2) |
| CO | 200 ppmvd (both natural gas and fuel oil #2) |
| $PM_{10}$ | 8.6 lb/hr (natural gas) |
| | 20 lb/hr (fuel oil #2) |
| $SO_x$ | 0.00285 lb/MMBtu (natural gas per APR 1720) |
| | 16.48 lb/hr (fuel oil #2) |

## C. <u>Calculations:</u>

### 1. Pre-Project Potential to Emit (PE1):

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. The criteria pollutant potentials to emit for each emission unit is presented below:

## VII. GENERAL CALCULATIONS (Continued):

### i. N-2246-3-0, N-2246-4-0, N-2246-5-0, & N-2246-6-0:

Since these are brand new emission units, the pre-project potential to emit (PE1) for all the emissions units associated with these permit units are equal to zero.

### ii. N-2246-1-3 & N-2246-2-3 (Simple-Cycle Combustion Turbine Generators):

***a. Maximum Daily PE1:***

Although each turbine's permit states that natural gas is the primary fuel and fuel oil #2 is to be used only in the event of a natural gas shortage, no quantifiable operational limitation is placed on the use of fuel oil #2. Therefore, except for NOx and $PM_{10}$ emissions, the worst-case daily emission rates will be calculated assuming operation on fuel oil #2 for 24 hr/day. For NOx emissions, the combined emissions from permit units N-2246-1 and N-2246-2 are limited by permit conditions to not exceed 1,020 lb/day. For $PM_{10}$ emissions, the combined emissions from permit units N-2246-1 and N-2246-2 are limited by permit conditions to not exceed 150 lb/day. The maximum daily emissions are calculated as follows, and summarized in the table below:

$$\text{Daily } PE_{CO\ (Fuel\ Oil\ \#2)} = [(\text{ppmvd}) \times \text{F-Factor (dscf/MMBtu)} \times \text{MW (lb/lb-mol)} \times \text{MMBtu/hr} \times 24\ \text{hr/day}] \div [\text{MSV (dscf/lb-mol)} \times ((20.9 - O_2\%) \div 20.9) \times 10^6]$$
$$= [(\text{ppmvd}) \times 9{,}051\ \text{dscf/MMBtu} \times 28\ \text{lb/lb-mol} \times 325\ \text{MMBtu/hr} \times 24\ \text{hr/day}] \div [379.5\ \text{dscf/lb-mol} \times ((20.9 - 15) \div 20.9) \times 10^6]$$

Daily $PE_{VOC,\ \&\ SOx\ (Fuel\ Oil\ \#2)}$ = $EF_{Fuel\ Oil\ \#2}$ lb/hr × 24 hr/day
Daily $PE_{NOx\ (Fuel\ Oil\ \#2)}$ = 1,020 lb NOx/day
Daily $PE_{PM10(Fuel\ Oil\ \#2)}$ = 150.0 lb $PM_{10}$/day

| Maximum Daily PE1 for Permit Units N-2246-1-3 & N-2246-2-3 | | | |
|---|---|---|---|
| Pollutant | $EF_{Fuel\ Oil\ \#2}$ (ppmvd @ 15% $O_2$) | $EF_{Fuel\ Oil\ \#2}$ (lb/hr) | Daily $PE_{Fuel\ Oil\ \#2/Each\ CTG}$ (lb/day) |
| NOx | 42.0 | 51.0 | **1,020.0** |
| CO | 200.0 | N/A | **3,690.3** |
| VOC | N/A | 15.0 | **360.0** |
| $PM_{10}$ | N/A | 20.0 | **150.0** |
| SOx | N/A | 16.48 | **395.5** |

***b. Maximum Quarterly and Annual PE1:***

Maximum quarterly and annual emissions will be calculated based on the worst-case of utilizing fuel oil #2, operating 219 hours/quarter, and operating 877 hours/year. The maximum quarterly and annual emissions are calculated as follows, and summarized in the table below:

## VII. GENERAL CALCULATIONS (Continued):

Quarterly $PE_{CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr × 219 hr/qtr] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr × 219 hr/qtr] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

$PE_{Quarterly\ NOx,\ VOC,\ SOx,\ \&\ PM10\ (Fuel\ Oil\ \#2)}$ = $EF_{100\%\ Load\ (Fuel\ Oil\ \#2)}$ lb/hr × 219 hr/qtr

Annual $PE_{CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr × 877 hr/day] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr × 877 hr/yr] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

Annual $PE_{NOx,\ VOC,\ PM10,\ \&\ SOx\ (Fuel\ Oil\ \#2)}$ = $EF_{Fuel\ Oil\ \#2}$ lb/hr × 877 hr/yr

| **Maximum Annual PE1 for Permit Units N-2246-1-3 & N-2246-2-3 (Each)** | | | |
|---|---|---|---|
| Pollutant | $EF_{Fuel\ Oil\ \#2}$ | Quarterly $PE1_{Fuel\ Oil\ \#2}$ (lb/quarter) | Annual $PE1_{Fuel\ Oil\ \#2/Each\ CTG}$ (lb/year) |
| NOx | 51.0 lb/hour | **11,169** | **44,727** |
| CO | 200.0 ppmvd @ 15% $O_2$ | **33,674** | **134,850** |
| VOC | 15.0 lb/hour | **3,285** | **13,155** |
| $PM_{10}$ | 20.0 lb/hour | **4,380** | **17,540** |
| SOx | 16.48 lb/hour | **3,609** | **14,453** |

### 2. Post-Project Potential to Emit (PE2):

### i. N-2246-3-0 & N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):

### *a. Maximum Hourly PE2:*

The maximum hourly potential to emit for $NO_X$, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. Maximum hourly emissions for $PM_{10}$, $SO_X$, and $NH_3$ will occur when the unit is operating at 100% load @ 32°F. The maximum hourly PE for NOx, CO, and VOC from the two CTGs operating simultaneously will occur when one turbine is in start-up mode and the other turbine is operating at 100% load @ 32° F. The maximum hourly PE, for $PM_{10}$, $SO_X$, and $NH_3$, from the two CTGs operating simultaneously will occur when the two units are operating at 100% load @ 32° F. The maximum hourly emissions are calculated as follows, and summarized in the table below:

## VII. GENERAL CALCULATIONS (Continued):

$PE_{1\ Hour/NOx,\ CO,\ \&\ VOC}$ = $EF_{Startup}$ lb/hr (only for the CTG operating in the startup mode)
$PE_{1\ Hour/NOx,\ CO,\ \&\ VOC}$ = $EF_{100\%\ Load\ @\ 32\ F}$ lb/hr (only for the CTG operating at 100% load)
$PE_{1\ Hour/PM10,\ SOx,\ \&\ NH3}$ = $EF_{100\%\ Load\ @\ 32\ F}$ lb/hr (for the CTGs operating at startup mode & 100% load)

| Maximum Hourly PE2 for Permits N-2246-3-0 & N-2246-4-0 | | | | | |
|---|---|---|---|---|---|
| Pollutant | $EF_{Startup}$ (lb/hr) | $EF_{100\%\ Load}$ (lb/hr) | $PE2_{1-Hour/StartUp}$ (lb/hr) | $PE2_{1-Hour/100\%\ Load}$ (lb/hr) | $PE2_{1-Hour/Combined\ Total\ of\ Both\ CTGs}$ (lb/hr) |
| NOx | 119.0 | 7.59 | 119.0 | 7.6 | **126.6** |
| CO | 129.0 | 9.25 | 129.0 | 9.3 | **138.3** |
| VOC | 16.0 | 1.84 | 16.0 | 1.8 | **17.8** |
| $PM_{10}$ | N/A[6] | 7.0 | 7.0 | 7.0 | **14.0** |
| SOx | N/A[6] | 1.05 | 1.1 | 1.1 | **2.2** |
| $NH_3$ | N/A[6] | 14.06 | 14.1 | 14.1 | **28.2** |

### *b. Maximum Daily PE2:*

Maximum daily emissions for $NO_X$, CO, and VOC occurs when each CTG undergoes 5 hours operating in cold startup mode and 19 hours operating at full load. Maximum daily emissions for $PM_{10}$, $SO_X$, and $NH_3$ occurs when each CTG operates 24 hours at 100% load @ 32$^o$ F. The results are summarized in the table below:

$PE_{Daily/NOx,\ CO,\ \&\ VOC}$ = 1 Cold Start/day × $EF_{5\text{-}hr\ Cold\ Startup}$ lb/start + 19 hr/day × $EF_{100\%\ Load}$ lb/hr
$PE_{Daily/PM10,\ SOx,\ \&\ NH3}$ = 24 hr/day × $EF_{100\%\ Load}$ lb/hr

| Maximum Daily PE2 for Permits N-2246-3-0 & N-2246-4-0 | | | | |
|---|---|---|---|---|
| Pollutant | $EF_{5\text{-}hr\ Cold\ Startup}$ (lb/start) | $EF_{100\%\ Load}$ (lb/hr) | $PE2_{Daily\ (per\ CTG)}$ (lb/day) | $PE2_{Daily/Combined\ Total\ of\ Both\ CTGs}$ (lb/day) |
| NOx | 300.0 | 7.59 | **444.2** | **888.4** |
| CO | 383.0 | 9.25 | **558.8** | **1,117.5** |
| VOC | 48.0 | 1.84 | **83.0** | **166.0** |
| $PM_{10}$ | N/A[7] | 7.0 | **168.0** | **336.0** |
| SOx | N/A[7] | 1.05 | **25.2** | **50.4** |
| $NH_3$ | N/A[7] | 14.06 | **337.4** | **674.8** |

[6] The maximum hourly emissions for this pollutant occur when each CTG operates at 100% load for 1 hour.
[7] Maximum daily emissions for this pollutant occur when each CTG is operated at 100% load for 24 hr/day.

## VII. GENERAL CALCULATIONS (Continued):

### *c. Maximum Quarterly PE2:*

The maximum NOx from each CTG per quarter will be calculated based on the applicants proposed combined total quarterly emission limit of 35,000 lb/quarter. The maximum CO, VOC, $PM_{10}$, SOx, and $NH_3$ emissions from each CTG per quarter will occur when each unit undergoes 74 startup/shutdown hours and 1,820 hours of operation at 100% load @ 61$^{o}$F. The maximum quarterly emissions are calculated as follows, and summarized in the tables below:

Quarterly $PE2_{NOx}$ = 35,000 lb/quarter (combined) ÷ 2 turbines
= 17,500 lb/quarter/turbine

Quarterly $PE2_{CO,\ VOC,\ PM10,\ SOx,\ NH3}$ = 74 startup/shutdown hr/qtr × $EF_{Startup/Shutdown}$ lb/hr + 1,820 hr/qtr × $EF_{100\%\ Load}$ lb/hr

| Maximum Quarterly PE2 for Permits N-2246-3-0 & N-2246-4-0 | | | | |
|---|---|---|---|---|
| Pollutant | $EF_{Startup/Shutdown}$ (lb/hr) | $EF_{100\%\ Load}$ (lb/hr) | $PE2_{Quarterly\ (per\ CTG)}$ (lb/qtr) | $PE2_{Quarterly/Combined\ Total\ of\ Both\ CTGs}$ (lb/qtr) |
| NOx | 119.0 | 7.18 | **17,500** | **35,000** |
| CO | 129.0 | 8.74 | **25,453** | **50,906** |
| VOC | 16.0 | 1.74 | **4,351** | **8,702** |
| $PM_{10}$ | N/A[8] | 7.0 | **13,258** | **26,516** |
| SOx | N/A[8] | 0.99 | **1,875** | **3,750** |
| $NH_3$ | N/A[8] | 13.28 | **25,152** | **50,304** |

### *d. Maximum Annual PE2:*

The maximum annual PE is merely the sum of the maximum quarterly PE calculated in section VII.C.2.i.c. of this document. The results are summarized in the table on the following page:

| Maximum Annual PE2 for Permits N-2246-3-0 & N-2246-4-0 | | | |
|---|---|---|---|
| Pollutant | $PE2_{Quarterly\ (per\ CTG)}$ (lb/qtr) | $PE2_{Annual\ (per\ CTG)}$ (lb/yr) | $PE2_{Annual\ (Combined\ Total\ of\ Both\ CTGs)}$ (lb/yr) |
| NOx | 17,500 | **70,000** | **140,000** |
| CO | 25,453 | **101,812** | **203,624** |
| VOC | 4,351 | **17,404** | **34,808** |
| $PM_{10}$ | 13,258 | **53,032** | **106,064** |
| SOx | 1,875 | **7,500** | **15,000** |
| $NH_3$ | 25,152 | **100,608** | **201,216** |

[8] Maximum daily emissions for this pollutant occur when each CTG is operated at 100% load for 1,894 hr/quarter.

## VII. GENERAL CALCULATIONS (Continued):

### ii. N-2246-5-0 (5-Cell Cooling Tower)

### *a. Maximum Hourly, Daily, Quarterly and Annual PE2*

Cooling towers are the source of $PM_{10}$ emissions only. Emissions can be calculated using the following equation and are summarized in the table below:

$PE_{PM10}$ = Water Circulation Rate (gal/min) × Drift Rate (%) × TDS Concentration (ppm) × Density of Water (lb/gal)

$PE_{Hourly\ PM10}$ = 68,500 gal/min × (0.0005 ÷ 100) × 7,500×$10^{-6}$ × 8.34 lb/gal × 60 min/hr
= **1.3 lb $PM_{10}$/hour**

$PE_{Daily\ PM10}$ = 68,500 gal/min × (0.0005 ÷ 100) × 7,500×$10^{-6}$ × 8.34 lb/gal × 60 min/hr × 24 hr/day
= **30.8 lb $PM_{10}$/day**

$PE_{Quarterly\ PM10}$ = 68,500 gal/min × (0.0005 ÷ 100) × 7,500×$10^{-6}$ × 8.34 lb/gal × 60 min/hr × 2,190 hr/qtr
= **2,815 lb $PM_{10}$/qtr**

$PE_{Annual\ PM10}$ = 68,500 gal/min × (0.0005 ÷ 100) × 7,500×$10^{-6}$ × 8.34 lb/gal × 60 min/hr × 8,760 hr/yr
= **11,260 lb $PM_{10}$/yr**

| Post Project Potential to Emit (PE2) for Permit N-2246-5-0 | | | | |
|---|---|---|---|---|
| Pollutant | Hourly PE2 (lb/hr) | Daily PE2 (lb/day) | Quarterly PE2 (lb/qtr) | Annual PE2 (lb/yr) |
| $PM_{10}$ | **1.3** | **30.8** | **2,815** | **11,260** |

### iii N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):

### *a. Maximum Hourly, Daily, Quarterly, and Annual PE2*

Maximum emissions from the IC engine will occur when operating at maximum capacity. The maximum hourly, daily, quarterly, and annual emissions are calculated as follows, and summarized in the table below:

$PE_{Hourly\ NOx,\ CO,\ VOC,\ PM10,\ \&\ SOx}$ = $EF_{Max.\ Capacity}$ g/hp hr × 300 hp × 1 lb/453.6 g

$PE_{Daily\ NOx,\ CO,\ VOC,\ PM10,\ \&\ SOx}$ = $EF_{Max.\ Capacity}$ g/hp hr × 300 hp × 1 hp/453.6 g × 24 hr/day

$PE_{Quarterly\ NOx,\ CO,\ VOC,\ PM10,\ \&\ SOx}$ = $EF_{Max.\ Capacity}$ g/hp hr × 300 hp × 1hp/453.6 g × 25 hr/qtr

## VII. GENERAL CALCULATIONS (Continued):

$PE_{Annual\ NOx,\ CO,\ VOC,\ PM10,\ \&\ SOx}$ = $EF_{Max.\ Capacity}$ g/hp hr × 300 hp × 1 lb/453.6 g × 100 hr/yr

| Post Project Potential to Emit (PE2) for Permit N-2246-6-0 | | | | | |
|---|---|---|---|---|---|
| Pollutant | $EF_{Max.\ Capacity}$ (g/hp-hr) | Hourly PE2 (lb/hr) | Daily PE2 (lb/day) | Quarterly PE2 (lb/qtr) | Annual PE2 (lb/yr) |
| NOx | 5.20 | **3.4** | **82.5** | **86** | **344** |
| CO | 0.27 | **0.2** | **4.3** | **5** | **18** |
| VOC | 0.15 | **0.1** | **2.4** | **3** | **10** |
| $PM_{10}$ | 0.09 | **0.1** | **1.4** | **2** | **6** |
| SOx | 0.16 | **0.1** | **2.5** | **3** | **11** |

### iv N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):

#### *a. Maximum Hourly and Daily PE2*

Maximum hourly and daily emission rates from these CTGs will occur when operating at 100% load and combusting fuel oil #2. The facility is proposing to maintain their current combined emission limits of 1,020 pounds of NOx/day and 150 pounds of $PM_{10}$ /day from these two CTGs. The maximum hourly and daily emissions are calculated as follows, and summarized in the table below:

$PE_{Hourly\ CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

$PE_{Hourly\ NOx,\ VOC,\ SOx,\ \&\ PM10\ (Fuel\ Oil\ \#2)}$ = $EF_{100\%\ Load\ (Fuel\ Oil\ \#2)}$ lb/hr

$PE_{Daily\ CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr × 24 hr/day] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr × 24 hr/day] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

$PE_{Daily\ VOC,\ \&\ SOx\ (Fuel\ Oil\ \#2)}$ = $EF_{100\%\ Load\ (Fuel\ Oil\ \#2)}$ lb/hr × 24 hr/day

$PE_{Daily\ NOx\ (Fuel\ Oil\ \#2)}$ = 1,020 lb NOx/day

$PE_{Daily\ PM10\ (Fuel\ Oil\ \#2)}$ = 150.0 lb $PM_{10}$/day

## VII. GENERAL CALCULATIONS (Continued):

| Maximum Hourly and Daily PE2 for Permits N-2246-1-4 and N-2246-2-4 | | | | | |
|---|---|---|---|---|---|
| Pollutant | $EF_{100\%\ Load}$ (Fuel Oil #2) | Hourly PE2 (per CTG) (lb/hr) | Hourly PE2 (Combined Total of Both CTGs) (lb/hr) | Daily PE2 (per CTG) (lb/day) | Daily PE2 (Combined Total of Both CTGs) (lb/day) |
| NOx | 51.0 lb/hr | **51.0** | **102.0** | **1,020.0** | **1,020.0** |
| CO | 200.0 ppmvd @ 15% $O_2$ | **153.8** | **307.6** | **3,690.3** | **7,380.6** |
| VOC | 15.0 lb/hr | **15.0** | **30.0** | **360** | **720.0** |
| $PM_{10}$ | 20.0 lb/hr | **20.0** | **40.0** | **150** | **150.0** |
| SOx | 16.48 lb/hr | **16.48** | **33.0** | **395.5** | **791.0** |

### *b. Maximum Quarterly and Annual PE2:*

Maximum quarterly and annual emission rates from these CTGs will occur when operating at 100% load, combusting fuel oil #2, operating 219 hours/quarter, and 877 hours/year. The maximum quarterly and annual emissions are calculated as follows, and summarized in the table below:

$PE_{Quarterly\ CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr × 219 hr/qtr] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr × 219 hr/qtr] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

$PE_{Quarterly\ VOC\ \&\ SOx\ (Fuel\ Oil\ \#2)}$ = $EF_{100\%\ Load\ (Fuel\ Oil\ \#2)}$ lb/hr × 219 hr/qtr

$PE_{Quarterly\ PM10\ (Fuel\ Oil\ \#2)}$ = 7,016 lb/yr ÷ 4 qtr/yr = 1,754 lb/qtr (proposed by the applicant)

$PE_{Annual\ CO\ (Fuel\ Oil\ \#2)}$ = [(ppmvd) × F-Factor (dscf/MMBtu) × MW (lb/lb-mol) × MMBtu/hr × 877 hr/day] ÷ [MSV (dscf/lb-mol) × ((20.9 – $O_2$%) ÷ 20.9) × $10^6$]
= [(ppmvd) × 9,051 dscf/MMBtu × 28 lb/lb-mol × 325 MMBtu/hr × 877 hr/qtr] ÷ [379.5 dscf/lb-mol × ((20.9 – 15) ÷ 20.9) × $10^6$]

$PE_{Annual\ NOx,\ VOC,\ SOx,\ \&\ PM10\ (Fuel\ Oil\ \#2)}$ = $EF_{100\%\ Load\ (Fuel\ Oil\ \#2)}$ lb/hr × 877 hr/day

$PE_{Annual\ PM10\ (Fuel\ Oil\ \#2)}$ = 7,016 lb/yr (proposed by the applicant)

| Maximum Quarterly and Annual PE2 for Permits N-2246-1-4 and N-2246-2-4 | | | | | |
|---|---|---|---|---|---|
| Pollutant | $EF_{100\%\ Load}$ (Fuel Oil #2) | Quarterly PE2 (per CTG) (lb/qtr) | Quarterly PE2 (Combined Total of Both CTGs) (lb/qtr) | Annual PE2 (per CTG) (lb/yr) | Annual PE2 (Combined Total of Both CTGs) (lb/yr) |
| NOx | 51.0 lb/hr | **11,169** | **22,338** | **44,727** | **89,454** |
| CO | 200.0 ppmvd @ 15% $O_2$ | **33,674** | **67,348** | **134,850** | **269,700** |
| VOC | 15.0 lb/hr | **3,285** | **6,570** | **13,155** | **26,310** |
| $PM_{10}$ | 20.0 lb/hr | **1,754** | **3,508** | **7,016** | **14,032** |
| SOx | 16.48 lb/hr | **3,609** | **7,218** | **14,453** | **28,906** |

## VII. GENERAL CALCULATIONS (Continued):

### 3. Quarterly Emission Change (∆PE):

The quarterly emission change is used to complete the emission profile for each emissions unit and is calculated as follows:

∆PE (lb/qtr) = Quarterly PE2 (lb/qtr) – Quarterly PE1 (lb/qtr)

**i. N-2246-3-0, N-2246-4-0, N-2246-5-0, & N-2246-6-0:**

Since the pre-project potential to emit (PE1) is equal to zero for all emissions units and for all criteria pollutants, ∆PE will be equivalent to the PE2 calculated above in Section VII.C.2.

**ii. N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

Pursuant to the Quarterly PE1 calculations in Section VII.C.1 and the Quarterly PE2 calculations in Section VII.C.2, the quarterly emission changes are summarized in the table below:

| **Quarterly Emission Changes ∆PE for Permits N-2246-1-4 and N-2246-2-4 (Each)** | | | |
|---|---|---|---|
| Pollutant | Quarterly PE2 (lb/qtr) | Quarterly PE1 (lb/qtr) | $\Delta PE_{(Per\ CTG)}$ (lb/qtr) |
| NOx | 11,169 | 11,169 | **0** |
| CO | 33,674 | 33,674 | **0** |
| VOC | 3,285 | 3,285 | **0** |
| $PM_{10}$ | 1,754 | 4,380 | **-2,626** |
| SOx | 3,609 | 3,609 | **0** |

### 4. Adjusted Increase in Permitted Emissions (AIPE):

**i. N-2246-3-0, N-2246-4-0, N-2246-5-0, & N-2246-6-0:**

District Rule 2201, Section 4.3 defines AIPE as the difference between an emission unit's post-project potential to emit (PE2) and the emission unit's Historically Adjusted Potential to Emit (HAPE): AIPE = PE2 – HAPE. Since these are new emission units, HAPE = 0, and AIPE = PE2 for all pollutants. Refer to section VII.C.2 of this document for the PE2 for each emissions unit.

## VII. GENERAL CALCULATIONS (Continued):

### ii. N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):

The adjusted increase in permitted emissions (AIPE) is calculated to determine if BACT is triggered for a modification to an emissions unit. For permits N-2246-1-4 and N-2246-2-4, the applicant is proposing no increase in daily fuel usage, emission rate, and is proposing no change to the control equipment. The applicant is not proposing an increase in emissions for any pollutant due to the proposed modification. Therefore, AIPE is equal to zero and BACT is not triggered (Ref Rule 2201, Section 4.1) for any pollutant.

### 5. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

| Pre-Project Stationary Source Potential to Emit (SSPE1) (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **$NO_X$** | **CO** | **VOC** | **$PM_{10}$** | **$SO_X$** | **$NH_3$** |
| N-2246-1-3 | 44,727 | 134,850 | 13,155 | 17,540 | 14,453 | 0 |
| N-2246-2-3 | 44,727 | 134,850 | 13,155 | 17,540 | 14,453 | 0 |
| **Total** | **89,454** | **199,999**[9] | **26,310** | **35,080** | **28,906** | **0** |
| Major Source Thresholds | 50,000 | 200,000 | 50,000 | 140,000 | 140,000 | N/A |
| Major Source? | **Yes** | No | No | No | No | N/A |

### 6. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-project Stationary Source Potential to Emit (SSPE2) is the post-project annual PE of all units at the Stationary Source.

[9] The stationary source CO emissions are limited by permit condition to less than 100 tons/yr.

## VII. GENERAL CALCULATIONS (Continued):

| Post-Project Stationary Source Potential to Emit (SSPE2) (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **$NO_X$** | **CO** | **VOC** | **$PM_{10}$** | **$SO_X$** | **$NH_3$** |
| N-2246-1-4 | 44,727 | 134,850 | 13,155 | 7,016 | 14,453 | 0 |
| N-2246-2-4 | 44,727 | 134,850 | 13,155 | 7,016 | 14,453 | 0 |
| N-2246-3-0 | 140,000[10] | 101,812 | 17,404 | 53,032 | 7,500 | 100,608 |
| N-2246-4-0 | | 101,812 | 17,404 | 53,032 | 7,500 | 100,608 |
| N-2246-5-0 | 0 | 0 | 0 | 11,260 | 0 | 0 |
| N-2246-6-0 | 344 | 18 | 10 | 6 | 11 | 0 |
| **Total** | **229,798** | **473,342** | **61,128** | **131,362** | **43,917** | **201,216** |
| Offset Thresholds | 20,000 | 200,000 | 20,000 | 29,200 | 54,750 | N/A |
| Offsets Triggered? | **Yes** | **Yes** | **Yes** | **Yes** | No | |
| Major Source Thresholds | 50,000 | 200,000 | 50,000 | 140,000 | 140,000 | N/A |
| Major Source? | **Yes** | **Yes** | **Yes** | **Yes** | No | N/A |

### 7. Baseline Emissions (BE)

**i. N-2246-3-0, N-2246-4-0, N-2246-5-0, & N-2246-6-0:**

Since these are brand new emission units, there are no baseline emissions associated with these permit units. Therefore, the BE is equal to zero for all pollutants.

**ii N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

District Rule 2201, Section 3.7.1 defines baseline emissions (BE) as the Pre-Project Potential to Emit for: (a). all non-major source pollutants, (b). for all “clean emission units” at an existing major source, (c). for all “fully-offset” emission units at a major source, and (d). for all “highly-utilized” emission units at a major source.

Pursuant to the SSPE2 calculations in Section VII.C.6. of this application review, the post-project facility is major source for NOx, CO, VOC, and $PM_{10}$ emissions and a non-major source for $SO_x$ emissions. Since this facility is a non-major source for SOx, the BE for this pollutant will be equal to the sum of the pre-project PE for all emission units effected by this proposed project.

[10] Applicant proposed combined annual NOx emission limit of 140,000 lb/yr.

## VII. GENERAL CALCULATIONS (Continued):

Section 3.12.2 of District Rule 2201 defines a "clean emissions unit" as a unit equipped with emission control technology that meets the requirements of achieved-in-practice Best Available Control Technology (BACT) as accepted by the Air Pollution Control Officer (APCO) during the five years immediately preceding the submission of a complete application. This application was deemed complete on December 11, 2002. The District's 1st quarter 2003 BACT Clearinghouse listed the following achieved-in-practice emission control technologies for NOx, CO, VOC, and $PM_{10}$, emissions from peak load gas turbine engines without heat recovery steam generators operated less than 877 hr/yr (BACT Guideline 3.4.4):

NOx: 42 ppmvd @ 15% $O_2$ (water injection system, or equal)

CO: PUC quality natural gas

VOC: PUC quality natural gas with fuel oil #2 as backup.

$PM_{10}$: Natural gas as a primary fuel, air intake filter, and a maximum lube vent exhaust visible emissions of 0% opacity with either a lube oil coalescer, a lube vent high efficiency particulate filter, or a lube vent routed to the turbine or exhaust for oxidiation.

Each turbine is currently equipped with a water injection system and has $NO_x$ emissions limited by permit condition to not exceed 42 ppmvd @ 15% $O_2$. Therefore, each turbine qualifies as a "clean emission unit" for $NO_x$ emissions.

Each turbine is permitted to use PUC quality natural gas as a primary fuel and fuel oil #2 is to be used only in the event of a natural gas shortage. Therefore, each turbine qualifies as a "clean emission unit" for VOC emissions.

For CO emissions, each turbine is limited by permit conditions to not exceed 200 ppmvd @ 15% $O_2$ from the use of either natural gas or fuel oil #2. Therefore, the CO emissions from the use of either natural gas or fuel oil #2 is equivalent and these turbines qualify as a "clean emission unit" for CO emissions.

Each turbine is permitted to use PUC quality natural gas as a primary fuel and equipped with air intake filters and a lube oil coalescer. Therefore, each turbine qualifies as a "clean emission unit" for $PM_{10}$ emissions.

Since the existing gas turbine engines qualify as a "clean emission unit" for NOx, CO, VOC, and $PM_{10}$ emissions pursuant to section 3.12.2, the BE will be equal to the pre-project potential to emit (PE1).

## VII. GENERAL CALCULATIONS (Continued):

### 9. Stationary Source Increase in Permitted Emissions (SSIPE)

The SSIPE shall be calculated on a pollutant-by-pollutant basis, as the sum of the Net Emission Change (NEC) calculated for all emissions units contained in the stationary source project. The NEC shall be calculated as follows:

NEC = PE – BE

where: NEC = Net Emissions Change for each emissions unit, lb/year.
PE = Post-project Potential to Emit for each emissions unit, lb/year.
BE = Baseline emissions for each emissions unit, lb/year.

Pursuant to Section VII.C.8.i of this application review for the new permit units N-2246-3-0, N-2246-4-0, N-2246-5-0, and N-2246-6-0, the BE is equal to zero. Therefore:

$NEC_{N\text{-}2246\text{-}3\text{-}0,\ N\text{-}2246\text{-}4\text{-}0,\ N\text{-}2246\text{-}5\text{-}0,\ \&\ N\text{-}2246\text{-}6\text{-}0} = PE2$

Pursuant to Section VII.C.8.ii of this application review for the existing permit units N-2246-1-4 and N-2246-2-4, the BE is equal to the pre-project potential to emit (PE1). Therefore:

$NEC_{N\text{-}2246\text{-}1\text{-}4\ \&\ N\text{-}2246\text{-}2\text{-}4}$ = PE2 – PE1 = 7,016 lb/yr – 17,540 lb/yr = -10,524 lb/yr

SSIPE = $\Sigma$NEC (lb/yr)
= $NEC_{N\text{-}2246\text{-}3\text{-}0} + NEC_{N\text{-}2246\text{-}4\text{-}0} + NEC_{N\text{-}2246\text{-}5\text{-}0} + NEC_{N\text{-}2246\text{-}6\text{-}0} + NEC_{N\text{-}2246\text{-}1\text{-}4} + NEC_{N\text{-}2246\text{-}2\text{-}4}$ (lb/yr)

| SSIPE (lb/yr) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit No.** | **$NO_X$** | **CO** | **VOC** | **$PM_{10}$** | **$SO_X$** | **$NH_3$** |
| N-2246-1-4 | 0 | 0 | 0 | 0[11] (-10,524) | 0 | 0 |
| N-2246-2-4 | 0 | 0 | 0 | 0[11] (-10,524) | 0 | 0 |
| N-2246-3-0 | 140,000 | 101,812 | 17,404 | 53,032 | 7,500 | 100,608 |
| N-2246-4-0 | | 101,812 | 17,404 | 53,032 | 7,500 | 100,608 |
| N-2246-5-0 | 0 | 0 | 0 | 11,260 | 0 | 0 |
| N-2246-6-0 | 344 | 18 | 10 | 6 | 11 | 0 |
| **Total** | **140,344** | **203,642** | **34,818** | **117,330** | **15,011** | **201,216** |

[11] Pursuant to District Rule 2201, Section 3.38.4, a SSIPE calculated to a negative value shall be set to zero.

## VII. GENERAL CALCULATIONS (Continued):

### 10. Contemporaneous Increase in Permitted Emissions (CIPE)

CIPE is required to determine if a Title I modification is triggered for a Major Source. Based on the pre and post-project stationary source potential to emit calculations (less onsite Emission Reduction Credit's) in Section VII.C.6. and VII.C.7. of this document, the facility is an existing Major Source for NOx. However, the facility will be a major source for CO, VOC, and $PM_{10}$ due to this proposed project. Therefore, the CIPE for NOx, CO, VOC, and $PM_{10}$ emissions will be calculated and summarized in the table below.

District Rule 2201, Section 3.14 defines the "contemporaneous period" as a period of five consecutive years immediately prior to the date of initiating construction on a new or modified emissions unit. The applicant is proposing to commence construction of the Walnut Energy Center in the first quarter of 2004. Therefore, for this project the contemporaneous period will begin on January 1, 1999.

| **CIPE (lb/yr)** | | | | | | |
|---|---|---|---|---|---|---|
| **Project No.** | **Permit No.** | **Action** | **NOx** | **CO** | **VOC** | **$PM_{10}$** |
| 1010301 (3/19/01) | N-2246-1-2<br>N-2246-2-2 | Modify permits to limit NOx to quarterly emission rates. | 0 | 0 | 0 | 0 |
| 1021732 (2/5/03) | N-2246-1-3<br>N-2246-2-1 | Modify permits to comply with District Rule 4703. | 0 | 0 | 0 | 0 |
| 1021521 | N-2246-1-4<br>N-2246-2-4<br>N-2246-3-0<br>N-2246-4-0<br>N-2246-5-0<br>N-2246-6-0 | Current Project | 140,344 | 203,642 | 34,818 | 117,330 |
| **Total** | | | **140,344** | **203,642** | **34,818** | **117,330** |
| **Title I Modification Thresholds** | | | **50,000** | **100,000** | **50,000** | **30,000** |
| **Title I Modification Triggered?** | | | **Yes** | **Yes** | No | **Yes** |

## VIII. COMPLIANCE:

***Rule 1080*** *Stack Monitoring (12/17/92)*

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

**VIII. COMPLIANCE (Continued):**

**N-2246-1-4, N-2246-2-4, N-2246-3-0, and N-2246-4-0**

The four CTGs will be equipped with operational CEMs for $NO_X$, CO, and $O_2$. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

***<u>Proposed Rule 1080 Conditions</u>:***

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- Permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- Permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions; nature and cause of excess (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

## VIII. COMPLIANCE (Continued):

***Rule 1081*** *Source Sampling (12/16/93)*

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

**N-2246-1-4, N-2246-2-4, N-2246-3-0, and N-2246-4-0**

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

***<u>Proposed Rule 1081 Conditions</u>:***

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of gas turbines (N-2246-3 or N-2246-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

- Source testing to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rule 1081]

**VIII. COMPLIANCE (Continued):**

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter, except after demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than quarterly. If a test shows noncompliance with the sulfur content requirement, the facility must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: PM10 - EPA Method 5 (front half and back half) or 201 and 202a, NOx - EPA Method 7E or 20, CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, ammonia - BAAQMD ST-1B, and fuel gas sulfur content - ASTM D3246. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

**N-2246-5-0**

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

***Proposed Rule 1081 Conditions:***

Compliance with PM10 emission limit shall be determined by a blowdown water sample analysis conducted by an independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

***Rule 1100*** *Equipment Breakdown (12/17/92)*

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

**VIII. COMPLIANCE (Continued):**

**N-2246-1-4, N-2246-2-4, N-2246-3-0, and N-2246-4-0**

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

***Proposed Rule 1100 Conditions:***

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

***Rule 2010*** *Permits Required (12/17/92)*

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, Walnut Energy Center is complying with the requirements of this Rule.

***Rule 2201*** *New and Modified Stationary Source Review Rule (04/25/02)*

***A. BACT:***

**1. BACT Applicability**

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, or $SO_X$. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

**N-2246-1-4 and N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

As shown in section VII.C.4.ii. of this document, AIPE is zero for all pollutants. BACT is not triggered for these units.

## VIII. COMPLIANCE (Continued):

**N-2246-3-0 & N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

As seen in Section VII.C.2.i.b. of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$. BACT is triggered for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$ criteria pollutants since the PEs are greater than 2 lb/day, and since the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.6 of this document.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for $NO_X$. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

**N-2246-5-0 (5-Cell Cooling Tower):**

As seen in Section VII.C.2.ii. of this evaluation, the applicant is proposing to install a new cooling tower with a PE greater than 2 lb/day for $PM_{10}$. BACT is triggered for the $PM_{10}$ criteria pollutant since the PE is greater than 2 lb/day.

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

As seen in Section VII.C.2.iii. of this evaluation, the applicant is proposing to install a new diesel-fired IC engine with a PE greater than 2 lb/day for $NO_X$, CO, VOC, and $SO_X$. BACT is triggered for $NO_X$, CO, VOC and $SO_X$ criteria pollutants since the PEs are greater than 2 lb/day, and since the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.6 of this document.

### 2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

## VIII. COMPLIANCE (Continued):

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery].

**N-2246-5-0 (5-Cell Cooling Tower):**

BACT Guideline 8.3.10 applies to the proposed 5 cell cooling tower. [Cooling Tower - Induced Draft, Evaporative Cooling].

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engines powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

### 3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units N-2246-3-0 and N-2246-4-0 see Attachment F.

For Permit Unit N-2246-5-0 see Attachment G.

For Permit Unit N-2246-6-0 see Attachment H.

### 4. BACT Summary:

**N-2246-3-0 and N-2246-4-0**

BACT has been satisfied by the following:

$NO_X$: 2.0 ppmv @ 15% $O_2$ (1-hour rolling average, except during startup/shutdown) with Dry Low $NO_X$ Combustors, SCR with ammonia injection and natural gas fuel

CO: 4.0 ppmv @ 15% $O_2$ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel

VOC: 2.0 ppmv @ 15% $O_2$ (3-hour rolling average, except during startup/shutdown)

## VIII. COMPLIANCE (Continued):

$PM_{10}$: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

$SO_X$: Natural gas with a sulfur content of 0.36 gr/100 scf

**N-2246-5-0**

BACT has been satisfied by the following:

$PM_{10}$: High efficiency (cellular type) drift eliminator

**N-2246-6-0**

BACT has been satisfied by the following:

$NO_X$: Certified $NO_X$ emissions of 5.20 g/hp-hr.

$PM_{10}$: Certified $PM_{10}$ emissions of 0.09 g/hp-hr.

$SO_X$: Low-sulfur diesel fuel (500 ppmv sulfur or less) or Very Low-sulfur diesel fuel (15 ppmv or less) where available

### *B. Offsets:*

### 1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for $NO_X$ and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for $SO_X$ and 29,200 lbs/year for $PM_{10}$. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for $NO_X$, CO, VOC and $PM_{10}$ emissions. Therefore, offset calculations are necessary.

| Offset Determination | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ |
| Post-project SSPE (SSPE2) | **229,798** | **473,342** | **61,128** | **131,362** | **43,917** |
| Offset Threshold | 20,000 | 200,000 | 20,000 | 29,200 | 54,750 |
| Offsets Triggered? | Yes | Yes | Yes | Yes | No |

## VIII. COMPLIANCE (Continued):

### 2. Quantity of Offsets Required:

**NOx, VOC, and $PM_{10}$:**

The SSPE1 of each NOx, VOC and $PM_{10}$ are greater than the offset threshold. Per Rule 2201 Section 4.7.1 the offset quantity will be the difference between the Post-Project Potential to Emit (PPE) of all new and modified units and the Baseline Emissions (BE) of all new and modified emission units.

Per Section 4.7.3, the quantity of offsets calculated shall be multiplied by the appropriate Distance Offset Ratio to determine the final quantity of offsets required.

Offset = $\Sigma$(PPE – BE) × Offset Ratio

where, Offset Ratio = Distance or interpollutant ratio of Sections 4.8 and 4.13.3

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit unit N-2246-6-0 will be exempt from providing offsets and the emissions associated with this permit unit contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = [$\Sigma$(PPE – BE) – (emergency equipment)] × Offset Ratio

<u>$NO_X$ Offset Calculations:</u>

For NOx emissions the $\Sigma$(PPE – BE) is equal to the SSIPE as calculated in Section VII.9. of this document, therefore:

$NO_X$ SSIPE = 140,344 lb/year
N-2246-6-0 (NOx) = 344 lb/year

NOx Offsets = [140,344 lb/yr – 344 lb/year] × Offset Ratio
= 140,000 lb/year × Offset Ratio

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly NOx Offsets = (140,000 lb/year ÷ 4 qtr/year) × Offset Ratio
= 35,000 lb/qtr × Offset Ratio

## VIII. COMPLIANCE (Continued):

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2:1 if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming an offset ratio of 1.5:1, the amount of $NO_X$ ERC credits that need to be surrendered to the District is:

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|
| 52,500 lb | 52,500 lb | 52,500 lb | 52,500 lb |

The applicant has stated that the facility plans to use ERC certificates C-482-2 and S-1834-2 to offset the increases in $NO_X$ emissions associated with this project. The above Certificates have available quarterly $NO_X$ credits as follows:

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| ERC #C-482-2 | 24,685 lb | 34,404 lb | 40,916 lb | 31,425 lb |
| ERC #S-1834-2 | 27,815 lb | 18,096 lb | 11,584 lb | 21,075 lb |
| Total: | 52,500 lb | 52,500 lb | 52,500 lb | 52,500 lb |

As seen above, the facility has sufficient credits to fully offset the quarterly $NO_X$ emissions.

VOC Offset Calculations:

For VOC emissions the $\Sigma$(PPE – BE) is equal to the SSIPE as calculated in Section VII.9. of this document, therefore:

VOC SSIPE = 34,818 lb/year
N-2246-6-0 (VOC) = 10 lb/year

VOC Offsets = [34,818 lb/year – 10 lb/year] $\times$ Offset Ratio
= 34,808 lb/year $\times$ Offset Ratio

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly VOC Offsets = (34,808 lb/year $\div$ 4 qtr/year) $\times$ Offset Ratio
= 8,702 lb/qtr $\times$ Offset Ratio

Assuming an offset ratio of 1.5:1, the amount of VOC ERC credits that need to be surrendered to the District is:

**VIII. COMPLIANCE (Continued):**

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|
| 13,053 lb | 13,053 lb | 13,053 lb | 13,053 lb |

The applicant has stated that the facility plans to use ERC certificate C-484-1 to offset the increases in VOC emissions associated with this project. The above Certificate has available quarterly VOC credits as follows:

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| ERC #C-484-1 | 13,350 lb | 13,350 lb | 13,350 lb | 13,350 lb |
| Total: | 13,350 lb | 13,350 lb | 13,350 lb | 13,350 lb |

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions.

$PM_{10}$ Offset Calculations:

For $PM_{10}$ emissions the $\Sigma$(PPE – BE) is summarized in the table below:

| Permit No. | PPE (lb $PM_{10}$/year) | BE (lb $PM_{10}$/year) | PPE – BE (lb $PM_{10}$/year) |
|---|---|---|---|
| N-2246-1-4 | 7,016 | 17,540 | -10,524 |
| N-2246-2-4 | 7,016 | 17,540 | -10,524 |
| N-2246-3-0 | 53,032 | 0 | 53,032 |
| N-2246-4-0 | 53,032 | 0 | 53,032 |
| N-2246-5-0 | 11,260 | 0 | 11,260 |
| N-2246-6-0 | 6 | 0 | 6 |
| **Total** | | | **96,282** |

N-2246-6-0 ($PM_{10}$) = 6 lb $PM_{10}$/year

$PM_{10}$ Offsets = [96,282 lb/year – 6 lb/year] $\times$ Offset Ratio
= 96,276 lb/year $\times$ Offset Ratio

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly $PM_{10}$ Offsets = (96,276 lb/year $\div$ 4 qtr/year) $\times$ Offset Ratio
= 24,069 lb/qtr $\times$ Offset Ratio

Assuming an offset ratio of 1.5:1, the amount of $PM_{10}$ ERC credits that need to be surrendered to the District is:

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|
| 36,104 lb | 36,104 lb | 36,104 lb | 36,104 lb |

**VIII. COMPLIANCE (Continued):**

The applicant has stated that the facility plans to use ERC certificates C-486-4,C-488-4, C-491-4, C-492-4, C-494-4, C-495-4, N-333-4, N-334-4, N-335-4, and N-336-4 to offset the increases in $PM_{10}$ emissions associated with this project. The above Certificates have available quarterly $PM_{10}$ credits as follows:

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| ERC #C-486-4 | 27,222 lb | 23,025 lb | 9,864 lb | 10,526 lb |
| ERC #C-488-4 | 654 lb | 0 | 0 | 20,809 lb |
| ERC #C-491-4 | 21,048 lb | 18,920 lb | 0 | 3,163 lb |
| ERC #C-492-4 | 0 | 0 | 0 | 625 lb |
| ERC #C-494-4 | 0 | 0 | 0 | 8,915 lb |
| ERC #C-495-4 | 0 | 0 | 0 | 13,992 lb |
| ERC #N-333-4 | 0 | 0 | 65 lb | 4,877 lb |
| ERC #N-334-4 | 2 | 0 | 0 | 1,367 lb |
| ERC #N-335-4 | 0 | 0 | 91 lb | 6,001 lb |
| ERC #N-336-4 | 0 | 0 | 0 | 2,834 lb |
| Total: | 48,926 lb | 41,945 lb | 10,020 lb | 73,109 lb |

As seen above, the facility is lacking sufficient credits to fully offset the emissions increases for $PM_{10}$ emissions occurring during the 3rd quarter. However, pursuant to District Rule 2201 Section 4.13.7, actual emissions reductions (AER) for PM that occurred from October through March may be used to offset increases in PM during any period of the year. Therefore, since the facility has surplus $PM_{10}$ credits available, which occurred within the 4th quarter, credits from that quarter can offset the deficient emissions in the 3rd quarter and the facility has sufficient offset credits to offset all increases in $PM_{10}$ emissions as demonstrated below.

Addition 3rd Quarter $PM_{10}$ Emission Offsets Required = 36,104 lb/qtr – 10,020 lb/qtr
= 26,084 lb/qtr

Available 4th Quarter $PM_{10}$ Emission Offsets = 73,109 lb/qtr – 36,104 lb/qtr
= 37,005 lb/qtr

Remaining 4th Quarter $PM_{10}$ ERCs Available = 37,005 lb/qtr – 26,084 lb/qtr
(after use in the 3rd Quarter) = 10,921 lb/qtr

**CO:**

CO offsets are triggered by CO emissions in excess of 200,000 lb/year for the facility. As shown previously, the SSPE2 for CO, after this project, is 473,342 lb/year, so offset requirements are triggered.

**VIII. COMPLIANCE (Continued):**

However, pursuant to Section 4.6.1, "Emission Offsets shall not be required for the following: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards (AAQS)."

The Technical Services Section of the San Joaquin Valley Unified Air Pollution Control District performed a CO modeling run, using the EPA ISCST3 air dispersion model, to determine if the CO emissions from the new facility would exceed the State and Federal AAQS (Attachment I). Modeling of the worst case 1 hour and 8 hour CO impacts were performed. These values were added to the worst case ambient concentration (background) measured and compared to the ambient air quality standards. Results of the modeling are presented below:

| **Ambient Modeling Results for CO** | | |
|---|---|---|
| | **1 hr std** | **8 hr std** |
| AAQS (ug/m$^3$) | 23,000 | 10,000 |
| Worst case ambient (background) (ug/m$^3$) | 4,078 | 3,029 |
| Modeled impact (ug/m$^3$) | **4,114** | **3,044** |
| Modeled ambient CO (ug/m$^3$) | **8,192** | **6,073** |

This modeling demonstrates that the proposed increase in CO emissions will not cause a violation of the CO ambient air quality standards. Therefore, the increase in CO emissions is exempt from offsets pursuant to Section 6.4.1.

***<u>C. Public Notification:</u>***

**1. Applicability**

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Title I modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Modifications with SSPE1 below an offset threshold and SSPE 2 above an offset threshold on a pollutant by pollutant basis (Existing Facility - Offset Threshold Notification)
- New stationary sources with SSPE2 exceeding offset thresholds (New Facility - Offset Threshold Notification)

## VIII. COMPLIANCE (Continued):

- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

### a. New Major Source Notice Determination:

As shown in section VII.D.5. of this document, the facility is currently a major source for NOx and a non-major source for CO, VOC, $PM_{10}$, and SOx. As shown in Section VII.D.6. of this document, the facility will also be a major source for CO, VOC, and $PM_{10}$ emissions after the proposed project. Therefore, public notice is required for this project for new Major Source purposes because the facility will be a new major source for CO, VOC, and $PM_{10}$.

### b. Title I Modification Notice Determination:

For existing facilities that are non-major sources prior to the modification, a Title I modification is triggered if the post project stationary source potential to emit (SSPE2) is increased to levels above the thresholds listed in Table 3-4 of District Rule 2201. For existing facilities that are major sources prior to the modification, a Title I modification is triggered if the Contemporaneous Increase in Permitted Emissions (CIPE), is equal to or greater than the thresholds listed in Table 3-5 of District Rule 2201.

The facility is an existing non-major source for CO, VOC, $PM_{10}$, and SOx prior to this project. As shown in section VII.C.6. of this document, SSPE2 for CO, VOC, and $PM_{10}$, will be greater than the thresholds listed in Table 3-5 of District Rule 2201 and SOx will be less than the referenced thresholds in Table 3-5 of District Rule 2201. Therefore, public noticing for Title I modification is required for CO, $PM_{10}$, and VOC, while public noticing for Title I modification is not required for SOx.

The facility is an existing major source only for NOx prior to the proposed project. It is necessary to determine whether the CIPE of NOx is greater than the above referenced NOx threshold listed in Table 3-5 of District Rule 2201.

As shown in section VII.C.10. of this document, CIPE for NOx is 140,344 lb NOx/year, which is greater than the NOx threshold of 50,000 lb/yr as listed in Table 3-5 of District Rule 2201. Therefore, Title I modification notice is triggered for NOx.

### c. PE Notification:

Applications, which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant, will trigger public noticing requirements. The potential to emit for each unit is summarized in the tables below.

## VIII. COMPLIANCE (Continued):

| Post-Project Potential to Emit for Permit N-2246-3-0 (lb/day) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **NOx** | **CO** | **VOC** | **$PM_{10}$** | **SOx** | **$NH_3$** |
| N-2246-3-0 | 444.2 | 558.8 | 83.0 | 168.0 | 25.2 | 337.4 |
| Threshold (lb/day) | 100 | 100 | 100 | 100 | 100 | 100 |
| Notification Required? | **Yes** | **Yes** | No | **Yes** | No | **Yes** |

| Post-Project Potential to Emit for Permit N-2246-4-0 (lb/day) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **NOx** | **CO** | **VOC** | **$PM_{10}$** | **SOx** | **$NH_3$** |
| N-2246-4-0 | 444.2 | 558.8 | 83.0 | 168.0 | 25.2 | 337.4 |
| Threshold (lb/day) | 100 | 100 | 100 | 100 | 100 | 100 |
| Notification Required? | **Yes** | **Yes** | No | **Yes** | No | **Yes** |

| Post-Project Potential to Emit for Permit N-2246-5-0 (lb/day) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **NOx** | **CO** | **VOC** | **$PM_{10}$** | **SOx** | **$NH_3$** |
| N-2246-5-0 | 0 | 0 | 0 | 30.8 | 0 | 0 |
| Threshold (lb/day) | 100 | 100 | 100 | 100 | 100 | 100 |
| Notification Required? | No | No | No | No | No | No |

| Post-Project Potential to Emit for Permit N-2246-6-0 (lb/day) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **NOx** | **CO** | **VOC** | **$PM_{10}$** | **SOx** | **$NH_3$** |
| N-2246-6-0 | 82.5 | 4.3 | 2.4 | 1.4 | 2.5 | 0 |
| Threshold (lb/day) | 100 | 100 | 100 | 100 | 100 | 100 |
| Notification Required? | No | No | No | No | No | No |

According to the tables above, permit units N-2246-3-0, and 4-0 will each have a Potential to Emit greater than 100 lb/day for $NO_X$, CO, $PM_{10}$ and $NH_3$ emissions. Therefore, public noticing will be required for PE > 100 lb/day purposes.

### d. Existing Facility - Offset Threshold Notification

Existing facilities with the SSPE1 below the offset threshold resulting in an SSPE2 exceeding the offset threshold due to the proposed project for one or more pollutants will require public noticing. As shown in Section VII.C. of this document, the SSPE2 of SOx are below the offset thresholds. For NOx, VOC, and $PM_{10}$ the SSPE1 and SSPE2 are above the offset threshold levels. For CO the SSPE1 was below the offset threshold and will be above the offset threshold due to the proposed project. Therefore, public noticing is required for offset threshold exceedence purposes.

**VIII. COMPLIANCE (Continued):**

**e. New Facility - Offset Threshold Notification**

This is an existing facility. This section does not require a public notification.

**f. SSIPE Notification:**

A notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/yr of any affected pollutant. As shown in section VII.C.9 of this document, the SSIPE for $NO_X$, CO, VOC, $PM_{10}$, and $NH_3$ will be more than 20,000 pounds per year. Therefore, a SSIPE notification is required for $NO_X$, CO, VOC, $PM_{10}$, and $NH_3$.

**2. Public Notice Requirements**

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, Title I Modification, PEs > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

***C. Daily Emission Limits:***

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.17 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.17.1 and 3.17.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis.

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

For these CTGs, the DELs for $NO_X$, CO, VOC, $PM_{10}$, $SO_X$, and $NH_3$ will consist of lb/day limits and/or emission factors.

***Proposed Rule 2201 (DEL) Conditions:***

**The following conditions will apply to post-commissioning operation:**

- The NOx emissions shall not exceed 119.0 lb/hour during start-up and/or shutdown periods. The start-up and/or shutdown duration shall not exceed 5.0 hr/day.
- The NOx emissions concentration during steady state operation shall not exceed 2.0 ppmvd @ 15% $O_2$ over a 1 hour rolling average. Steady-state period refers to any period that is not a start-up or shut down period.

## VIII. COMPLIANCE (Continued):

- The combined total NOx emissions from start-up, shut down, and steady state operation shall not exceed 444.2 lb NOx/day.
- The CO emissions shall not exceed 129.0 lb/hour during start-up and/or shutdown periods. The start-up and/or shutdown duration shall not exceed 5.0 hr/day.
- The CO emissions concentration during steady state operation shall not exceed 4.0 ppmvd @ 15% $O_2$ over a 3 hour rolling average. Steady-state period refers to any period that is not a start-up or shut down period.
- The combined total CO emissions from start-up, shut down, and steady state operation shall not exceed 558.8 lb CO/day.
- The VOC emissions shall not exceed 16.0 lb/hour during start-up and/or shutdown periods. The start-up and/or shutdown duration shall not exceed 5.0 hr/day.
- The VOC emissions concentration during steady state operation shall not exceed 1.4 ppmvd @ 15% $O_2$ over a 3 hour rolling average. Steady-state period refers to any period that is not a start-up or shut down period.
- The combined total VOC emissions from start-up, shut down, and steady state operation shall not exceed 83.0 lb VOC/day.
- The $PM_{10}$ emissions rate shall not exceed 7.0 lb/hr and 168.0 lb/day.
- The SOx emissions rate shall not exceed 1.05 lb/hr and 25.2 lb/day.
- The ammonia ($NH_3$) emission concentration shall not exceed 10 ppmvd @ 15% $O_2$ over a 24 hour rolling average.

**The following condition will apply to commissioning activities:**

- The emissions from this unit, during the commissioning period, shall not exceed any of the following: NOx (as NO2) – 108.8 lb/hr, CO – 180.0 lb/hr, VOC (as methane) – 17.0 lb/hr, SOx – 0.94 lb/hr, and PM10 – 7.0 lb/hr.
- The total commissioning period for this unit shall not exceed 288 hours and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.

**N-2246-5-0 (5-Cell Cooling Tower):**

For the cooling tower, the DEL for $PM_{10}$ will consist of an emission limit (lb/day).

***Proposed Rule 2201 (DEL) Condition:***

- PM10 emission rate shall not exceed 30.8 lb/day.

## VIII. COMPLIANCE (Continued):

### N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

***Proposed Rule 2201 (DEL) Condition:***

- $NO_X$ emissions shall not exceed 5.20 g/hp-hr.
- CO emissions shall not exceed 0.27 g/hp-hr.
- VOC emissions shall not exceed 0.15 g/hp-hr.
- $PM_{10}$ emissions shall not exceed 0.09 g/hp-hr. [District Rule 2201]
- Only CARB-certified diesel fuel containing not more than 0.05% sulfur by weight shall be used.

### N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):

For these CTGs, the DELs for NOx, CO, VOC, $PM_{10}$, and SOx will consist of lb/day limits and/or emission factors.

***Proposed Rule 2201 (DEL) Condition:***

- When firing on natural gas, $NO_x$ (referenced as $NO_2$) emissions shall not exceed 25.0 ppmvd @ 15% $O_2$, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods).
- When firing on fuel oil, $NO_x$ (referenced as $NO_2$) emissions shall not exceed 42.0 ppmvd @ 15% $O_2$ and 51 lb/hr, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods).
- When firing on either natural gas or fuel oil, VOC emissions shall not exceed 15.00 lb/hr.
- When firing on either natural gas or fuel oil, CO emissions shall not exceed 200 ppmvd @ 15% $O_2$, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods).
- When firing on natural gas, $PM_{10}$ emissions shall not exceed 8.60 lb/hr.
- When firing on fuel oil, $PM_{10}$ emissions shall not exceed 20.00 lb/hr.
- The combined NOx emissions from permits N-2246-1 and N-2246-2 shall not exceed 1,020 lb/day and 25,551 lb/qtr.
- The combined $PM_{10}$ emissions from permits N-2246-1 and N-2246-2 shall not exceed 150 lb/day.

**VIII. COMPLIANCE (Continued):**

- When firing on natural gas, $SO_x$ emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]
- When firing on fuel oil, $SO_x$ emissions shall not exceed 16.37 lb/hr.

***<u>D. Annual Emission Limits:</u>***

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

The applicant is proposing to limit the annual emissions from these CTGs to include emissions from the commissioning activities. Therefore, an annual emission rate will be required to verify compliance with the annual emission limit. However, for $PM_{10}$ emissions the applicant is proposing commissioning period emissions equal to the normal steady state daily emission rates. For SOx emissions the applicant is proposing commissioning period emissions less than normal steady state daily emission rates. For NOx, CO, and VOC emissions the applicant is proposing commissioning period emissions greater than normal steady state daily emission rates. Therefore, it will only be necessary to utilize a permit condition to the limit the annual NOx, CO, and VOC emissions.

In addition, the applicant is proposing to limit the combined NOx emissions from the two new CTGs to 35,000 pounds/quarter and 140,000 pounds/year to avoid providing additional NOx offsets due to the proposed new CTGs.

***<u>Proposed Rule 2201 Annual Emission Limit Conditions</u>:***

- The cumulative annual emissions shall not exceed 101,812 lb for CO and 17,404 lb for VOC.
- The cumulative quarterly NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 35,000 pounds.
- The cumulative annual NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 140,000 pounds.

**N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

The applicant is proposing to limit the annual $PM_{10}$ emissions from each CTG to 7,016 pounds to offset the $PM_{10}$ emission increases due to this proposed project. Therefore, an annual $PM_{10}$ emission rate will be required to verify compliance with the annual $PM_{10}$ emission limit.

***<u>Proposed Rule 2201 Annual Emission Limit Conditions</u>:***

- The cumulative annual $PM_{10}$ emissions shall not exceed 7,016 pounds.

**VIII. COMPLIANCE (Continued):**

***E. Compliance Certification:***

Section 4.14.3 of this Rule requires the owner of a new major source or a source undergoing a Title I modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed in Sections VIII.C.1.a and VIII.C.1.b, this facility is a new major source and this project does constitute a Title I modification, therefore this requirement is applicable. Included in Attachment J is Turlock Irrigation District's certification.

***F. Air Quality Impact Analysis:***

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment I of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NOx, CO and SOx. As shown by the AQIA summary sheet the proposed equipment will not cause a violation of an air quality standard for NOx, CO or SOx.

The proposed location is located in a non-attainment area for PM10. The increase in the ambient PM10 concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

| Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2) | | | | | |
|---|---|---|---|---|---|
| Pollutant | Annual Avg. | 24 hr Avg. | 8 hr Avg. | 3 hr Avg. | 1 hr Avg. |
| PM10 | 1.0 | 5.0 | N/A | N/A | N/A |

| Calculated Contributions ($\mu g/m^3$) | | | | | |
|---|---|---|---|---|---|
| Pollutant | Annual Avg. | 24 hr Avg. | 8 hr Avg. | 3 hr Avg. | 1 hr Avg. |
| PM10 | 0.25 | 1.48 | N/A | N/A | N/A |

As shown, the calculated contribution of PM10 will not exceed the EPA significance level. This project is not expected to make worse a violation of an air quality standard.

This AQIA was based upon the hourly NOx, CO and VOC emissions proposed by the facility, which included commissioning for up to 288 hours. In order for these results to be valid, the following condition will be placed on ATCs N-2246-3-0 and N-2246-4-0:

**VIII. COMPLIANCE (Continued):**

- The NOx emissions shall not exceed 108.8 lb/hr, the CO emissions shall not exceed 180.0 lb/hr and the VOC emissions shall not exceed 17.0 lb/hr during commissioning periods.

***G. Compliance Assurance:***

**1. Source Testing**

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

District Rule 4703 requires $NO_X$ and CO emission testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and $PM_{10}$ emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for $NO_X$, VOC, CO, $PM_{10}$, and ammonia slip will be required within 120 days of initial operation and at least once every 12 months thereafter.

Also, initial source testing of $NO_X$, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. If CEM data is not certifiable to determine compliance with $NO_X$ and CO startup emission limits, then source testing to measure startup $NO_X$ and CO mass emission rates shall be conducted at least once every 12 months. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for $NO_X$, CO, and $O_2$. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of $NO_X$ and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart GG requires fuel nitrogen content testing. The District will accept the $NO_X$ source testing required by District Rule 4703 as equivalent to fuel nitrogen content testing.

40 CFR Part 60 subpart GG requires that fuel sulfur content be monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

**VIII. COMPLIANCE (Continued):**

**N-2246-5-0 (5-Cell Cooling Tower):**

The cooling tower will have a very large exhaust source, which will be very high in humidity. Such sources do not lend themselves well to source testing. Source testing is not required per District Policy APR-1705-1, Section I.E.

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

District Rule 4701 requires $NO_X$, CO, and VOC emission testing on a biennial basis (once every 24 months). Since these engines are limited to emergency operation only, they are exempt from the source testing requirements of the rule. Therefore, no source testing will be required for these permit units.

**N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

Section 6.3.2 of District Rule 4703 currently requires TID to conduct biennial source testing for each turbine to verify compliance with the $NO_x$ and CO emission limits. Therefore, no additional sources testing requirements or frequencies are necessary. Please refer to the discussion for Rule 4703 in section VIII of this document for detailed source testing requirements.

**2. Monitoring**

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

Monitoring of $NO_X$ emissions is required by District Rule 4703. The applicant has proposed a CEMS for $NO_X$.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart GG requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel nitrogen content. As stated in the Subpart GG compliance section of this document, the District will allow the annual $NO_X$ source test to substitute for this requirement.

**VIII. COMPLIANCE (Continued):**

40 CFR Part 60 Subpart GG requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require only annual fuel sulfur content testing if the $SO_X$ emission factor is based on a fuel sulfur content of 1.0 gr/scf. However, the applicant is proposing a $SO_X$ emission factor based on a fuel sulfur content of 0.36 gr/scf. For such units, fuel sulfur content testing is required more frequently. The facility will be required to test fuel sulfur content weekly until eight consecutive tests show compliance. After that, the testing frequency may be reduced to quarterly. If a quarterly test fails to show compliance then the testing returns to weekly until eight consecutive weekly tests show compliance. After that, the testing frequency may return to quarterly.

**N-2246-5-0 (5-Cell Cooling Tower):**

District Rule 7012 requires hexavalent chromium concentration testing to be conducted at least once every six (6) months for non-wooden cooling towers subject to Section 5.2.3 of the rule. Since the cooling tower has never had hexavalent chromium containing compounds added to the circulating water, this unit is exempt from the monitoring requirements of the rule. Therefore, no monitoring will be required for this permit unit.

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

District Rule 4701 requires the monitoring of $NO_X$ and CO emission. As discussed earlier, since the engines are limited to emergency operation only, they are exempt from the monitoring requirements of the rule. Therefore, no monitoring will be required for these permit units.

**N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

Monitoring of $NO_x$ emissions is required by District Rule 4703. The only emission control system employed on each turbine is a water injection system. Therefore, per Section 6.2.2 of Rule 4703, the owner is required to monitor operational characteristics recommended by the turbine manufacturer or emission control system supplier.

District Rule 4703 requires the facility to monitor the water injection rate. Water injection rate monitoring will be required.

District Rule 4703 requires the facility to monitor the exhaust temperature and exhaust flow rate. Exhaust temperature and exhaust flow rate monitoring will be required.

District Rule 4703 requires that the elapsed time of operation, on an annual basis be monitored. Such monitoring will be required.

## VIII. COMPLIANCE (Continued):

40 CFR Part 60 Subpart GG requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel to water injection ratio. Fuel to water injection ratio monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel nitrogen content. As stated in the Subpart GG compliance section of this document, the District will allow the annual NOx source test to substitute for this requirement.

40 CFR Part 60 Subpart GG requires monitoring of the fuel sulfur content . The gas supplier, Pacific Gas and Electric Company, may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require only annual fuel sulfur content testing if the SOx emission factor is based on a fuel sulfur content of 1.0 gr/scf. The facility emissions were based on a worse case fuel sulfur content of 1.0 gr/scf. Therefore, only annual fuel sulfur content testing will be required. For fuel oil #2, the sulfur content of the fuel oil will be determined each time fuel is transferred into the on-site storage tank.

### 3. Recordkeeping

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.G.2 of this document for a discussion of the parameters that will be monitored.

**N-2246-5-0 (5-Cell Cooling Tower):**

District Rule 7012 requires any person subject to Sections 5.2.2 and 5.2.3 of the rule to keep records of all circulating water tests performed. As discussed above, the cooling tower is exempt from the monitoring/testing requirements of the rule. Therefore, no recordkeeping will be required for this permit unit.

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

The applicant will be required to keep records of the hours of emergency and non-emergency operation in order to maintain the exemption from the other requirements of District Rule 4701.

## VIII. COMPLIANCE (Continued):

**N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.G.2 of this document for a discussion of the parameters that will be monitored.

### 4. Reporting

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

40 CFR Part 60 Subpart GG requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart GG requires the reporting of exceedences of the $NO_X$ emission limit of the permit. Such reporting will be required.

**N-2246-5-0 (5-Cell Cooling Tower):**

District Rule 7012 requires the facility submit a compliance plan to the APCO at least 90 days before the newly constructed cooling tower is operated. Such reporting will be required.

**N-2246-6-0 (Diesel-Fired Emergency IC Engine Powering a Fire Pump):**

There are no reporting requirements applicable to the emergency IC engine.

**N-2246-1-4 & N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

40 CFR Part 60 Subpart GG requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart GG requires the reporting of exceedences of the $NO_X$ emission limit of the permit. Such reporting will be required.

***Rule 2520*** *Federally Mandated Operating Permits (06/21/01)*

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.2 states, “Any source that emits or has the potential to emit 100 tons per year of any air contaminant.” The facility has the potential to emit greater than 100 tons per year of $NO_X$ and CO.

**VIII. COMPLIANCE (Continued):**

- Section 2.3 states, "Any major source." The facility will be a major source for $NO_X$, CO, VOC, and $PM_{10}$.

- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA…" The turbines are subject to NSPS.

- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.

- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is required to obtain a PSD permit from the EPA.

Pursuant to Rule 2520 Section 5.3.1, WEC must submit a Title V application within 12 months of commencing operations. No action is required at this time.

***<u>Proposed Rule 2520 Condition</u>:***

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

***Rule 2540*** *Acid Rain Program (11/13/97)*

The proposed CTGs are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in the second quarter of 2004.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the $NO_X$ and $SO_X$ emissions and a relatively small quantity of $SO_X$ allowances (from a national $SO_X$ allowance bank) will be required as well as the use of a $NO_X$ CEM.

## VIII. COMPLIANCE (Continued):

***Proposed Rule 2540 Condition:***

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

***Rule 2550*** *Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)*

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[12]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Risk Management Policy for Permitting New and Modified Sources, March 2001; APR 1905). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[13] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low $NO_X$ combustor-equipped large frame turbine.

[12] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).
[13] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

## VIII. COMPLIANCE (Continued):

**Hazardous Air Pollutant Emissions**
**Combined-Cycle Combustion Turbine Generators (N-2246-3-0 & N-2246-4-0)**

| Hazardous Air Pollutant | CATEF Emission Factor (lb/MMSCF)(1) | Maximum Hourly Emissions per Turbine (lb/hr) (2) | Maximum Annual Emissions per Turbine (tpy) (3) | Maximum Annual Emissions Two Turbines (tpy) |
|---|---|---|---|---|
| Acetaldehyde | 4.08E-02 | 0.042 | 0.173 | 0.3 |
| Acrolein | 3.69E-03 | 0.0038 | 0.0156 | 0.3 |
| Benzene | 3.33E-03 | 0.0034 | 0.0141 | 0.03 |
| 1,3-Butadiene | 4.39E-04 | 4.49E-04 | 0.00186 | 0.004 |
| Ethyl benzene | 3.26E-02 | 0.033 | 0.138 | 0.3 |
| Formaldehyde | 1.65E-01 | 0.169 | 0.698 | 1.4 |
| Hexane | 2.59E-01 | 0.265 | 1.095 | 2.2 |
| Naphthalene | 1.33E-03 | 0.00136 | 0.00563 | 0.01 |
| Polycyclic aromatic hydrocarbons (PAH) | --- | --- | --- | --- |
| Anthracene | 3.38E-05 | 3.45E-05 | 1.43E-04 | 0.0003 |
| Benzo(a)anthracene | 2.26E-05 | 2.3E-05 | 9.56E-05 | 0.0002 |
| Benzo(a)pyrene | 1.39E-05 | 1.42E-05 | 5.88E-05 | 0.0001 |
| Benzo(b)fluoranthrene | 1.13E-05 | 1.15E-05 | 4.78E-05 | 0.0001 |
| Benzo(k)fluoranthrene | 1.10E-05 | 1.12E-05 | 4.65E-05 | 0.00009 |
| Chrysene | 2.52E-05 | 2.58E-05 | 1.07E-04 | 0.0002 |
| Dibenz(a,h)anthracene | 2.35E-05 | 2.4E-05 | 9.94E-05 | 0.0002 |
| Indeno(1,2,3-cc)pyrene | 2.35E-05 | 2.4E-05 | 9.94E-05 | 0.0002 |
| Propylene oxide | 2.96E-02 | 0.03 | 0.13 | 0.3 |
| Toluene | 1.33E-01 | 0.14 | 0.56 | 1.1 |
| Xylenes | 6.53E-02 | 0.067 | 0.28 | 0.6 |
| **Total** | | | **3.11** | **6.25** |

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 1,046.8 MMBtu/hr and fuel HHV of 1,024.23 Btu/scf (1.022 MMscf/hr).
(3) Based on a maximum annual turbine fuel use of 8,664,245 MMBtu/year and fuel HHV of 1,024.23 Btu/scf (8,459.3 MMscf/yr).

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

**VIII. COMPLIANCE (Continued):**

Noncriteria pollutant emissions from the cooling tower were calculated from an analysis of cooling tower water supplies.

**Hazardous Air Pollutant Emissions**
**WEC – 5-Cell Cooling Tower(1) (N-2246-5-0)**

| Hazardous Air Pollutant | Concentration in Cooling Tower Return Water | Maximum Hourly Emissions (lb/hr) | Maximum Annual Emissions (lb/yr) | Maximum Annual Emissions (tpy) |
|---|---|---|---|---|
| Ammonia | 17.5 ppm | 0.003 | 26.3 | 0.01 |
| Copper | 0.027 ppm | 4.6E-06 | 0.04 | 2.0E-05 |
| Chloride | 250 ppm | 0.043 | 375.3 | 0.2 |
| Sulfate | 750 ppm | 0.13 | 1,126.0 | 0.6 |
| Zinc | 0.219 ppm | 3.75E-05 | 0.33 | 1.6E-04 |
| HAPs | -- | -- | -- | -- |
| Arsenic | 0.027 ppm(2) | 4.6E-06 | 0.04 | 2.0E-05 |
| Cadmium | 0.005 ppm | 8.6E-07 | 0.0075 | 3.8E-06 |
| Chromium | 0.011 ppm | 1.9E-06 | 0.017 | 8.3E-06 |
| Lead | 0.033 ppm(2) | 5.7E-06 | 0.05 | 2.5E-05 |
| Manganese | 0.129 ppm | 2.2E-05 | 0.19 | 9.7E-05 |
| Nickel | 0.027 ppm(2) | 4.6E-06 | 0.041 | 2.0E-05 |
| Selenium | 0.027 ppm(2) | 4.6E-06 | 0.041 | 2.0E-05 |
| **Total** | | | **1,528.4** | **0.77** |

(1) Emissions calculated from maximum drift rate of 171.39 lb/hr.
(2) Compounds identified as present in concentrations less than the limit of detection. Value listed is the detection limit.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the proposed new CTGs at the Walnut Energy Center will not be a major air toxics source and the provisions of this rule do not apply.

***Rule 4001*** *New Source Performance Standards*

**<u>40 CFR 60 – Subpart GG</u>**

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after 10/03/77. Therefore, this subpart applies to the new turbine installations.

***§60.332: Standards for Nitrogen Oxides***

Per §60.332(b) electric utility stationary gas turbines rated at over 100 MMBtu/hr are subject to §60.332(a). This section requires that the NOx emission limit be determined utilizing the following equation:

$$STD = 0.0075\left(\frac{14.4}{Y}\right) + F$$

## VIII. COMPLIANCE (Continued):

where: STD = Allowable NOx emissions in percent by volume @ 15% $O_2$, on a dry basis
Y = Manufacturer's rated heat rate at rated peak load (kJ/watt-hour), or actual measured heat rate at LHV and peak load. Y shall not exceed 14.4 kJ/watt hour.
F = Since natural gas is comprised of mostly methane, it is assumed that natural gas has essentially no fuel bound nitrogen, so F is set equal to 0. As a conservative estimate, it is assumed that fuel oil #2 also contains no fuel bound nitrogen. Fuel-bound nitrogen allowance (F = 0 for natural gas)

**N-2246-3-0 and N-2246-4-0 (Combined-Cycle Combustion Turbine Generators):**

For these CTGs the manufacturer's heat rate is 11,713 Btu/KW-hr, therefore:

Y = manufacturers rated heat load (kJ/W-hr)
= (11,713 Btu/kW-hr)(kW/1,000 W)(1,054.2 J/Btu)(kJ/1,000 J)[(14)]
= 12.35 kJ/W-hr (less than 14.4 kJ/W hour)

F = 0 (fuel bound nitrogen for natural gas fuel)

STD (% by vol @ 15% $O_2$) = 0.0075(14.4/12.35)+ 0
= 0.0087 %
= 87 ppmv @ 15% O2

For these CTGs the applicant is proposing a $NO_X$ concentration limit of 2.0 ppmv @ 15% $O_2$ (1 hr average) as required by BACT. Therefore, compliance with the NSPS $NO_X$ standard is expected.

**N-2246-1-4 and N-2246-2-4 (Simple-Cycle Combustion Turbine Generators):**

For these CTGs the manufacturer's heat rate is 13.76 kJ/watt-hour, therefore:

Y = 13.76 kJ/W-hr (less than 14.4 kJ/W hour)

F = 0 (fuel bound nitrogen for natural gas or fuel oil #2)

STD (% by vol @ 15% $O_2$) = 0.0075(14.4/13.76)+ 0
= 0.0078 %
= 78 ppmv @ 15% O2

[14] The rated heat load for the General Electric Frame 7EA turbine is 11,713 Btu/kW-hr, based on 84,440 KW nominal rating and a 989 MMBtu/hr heat input rating (HHV, full load, and 61 °F).

## VIII. COMPLIANCE (Continued):

For these CTGs, the $NO_X$ emissions will be limited by permit condition to 25.0 ppmvd @ 15% $O_2$ when firing on natural gas and 42.0 ppmvd @ 15% O2 when firing on fuel oil #2. Therefore, compliance with the NSPS $NO_X$ standard is expected.

***<u>§60.333: Standards for Sulfur Dioxide</u>***

Paragraphs (a) and (b) define the applicable $SO_X$ limits as follows:

(a). Emissions of sulfur dioxide shall not exceed 0.015 percent by volume (dry) @ 15% $O_2$ (150 ppmvd @ 15% $O_2$).
(b). No fuel shall be burned which contains sulfur in excess of 0.8 percent by weight.

The 150 ppmvd @ 15% $O_2$ limit specified in §60.333, paragraph (a) is equivalent to 0.769 lb-$SO_X$/MMBtu (for natural gas) and 263.59 lb-$SO_x$/hr (for fuel oil #2) as follows:

<u>Natural gas</u>:

$$\frac{(150\ \text{ppmvd})\times\left(8{,}578\,\frac{\text{ft}^3}{\text{MMBtu}}\right)\times\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)\times\left(\frac{20.9}{20.9-15}\right)}{\left(379.5\,\frac{\text{ft}^3}{\text{lb}-\text{mol}}\right)\times\left(10^6\right)} = 0.769\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

<u>Fuel oil #2</u>:

$$\frac{(150\ \text{ppmvd})\times\left(9{,}051\,\frac{\text{ft}^3}{\text{MMBtu}}\right)\times\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)\times\left(325\,\frac{\text{MMBtu}}{\text{hr}}\right)}{\left(379.5\,\frac{\text{ft}^3}{\text{lb}-\text{mol}}\right)\times\left(10^6\right)\times\left(\frac{20.9-15}{20.9}\right)} = 263.59\,\frac{\text{lb}-\text{SO}_x}{\text{hr}}$$

$SO_X$ emissions are limited to 0.0010 lb-$SO_x$/MMBtu (based on a sulfur content of 0.36 grain/100 scf) when combusting natural gas and 16.73 lb/hr when combusting fuel oil #2.

$SO_X$ emissions are based on combusting natural gas with a fuel sulfur content of 0.36 gr/100 scf, which results in an emission rate of 0.0010 lb-$SO_X$/MMBtu. The percent sulfur by weight of natural gas of 0.36 gr-S/100 scf natural gas is 0.00121, determined as follows (assuming a 100 scf sample comprised of methane at 60 °F). In addition, the sulfur content of any liquid fuel used is limited by §3.12 of District Rule 4703 to less than 0.05% by weight:

$$\left(\frac{0.36\,\text{gr}-\text{S}}{100\,\text{ft}^3-\text{NG}}\right)\times\left(\frac{\text{lb}-\text{S}}{7000\,\text{gr}-\text{S}}\right)\times\left(\frac{\text{ft}^3-\text{NG}}{0.0424\,\text{lb}-\text{NG}}\right) = 1.21\times10^{-5}\,\frac{\text{lb}-\text{S}}{\text{lb}-\text{NG}}$$

## VIII. COMPLIANCE (Continued):

Both $SO_X$ emissions and fuel sulfur content for each fuel are less than that required by Subpart GG. Recordkeeping and reporting of the fuel sulfur content is required as specified in section 60.334 (b)(2). Reporting will be performed using an alternative custom reporting schedule.

Reporting and notifications, and initial compliance testing will be required as specified in 40 CFR, Subpart A. Compliance is expected.

***§60.334: Monitoring of Operations***

Paragraph (a) requires owners or operators of any stationary gas turbine subject to this subpart and using water injection to control NOx emissions to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in each turbine. This will only apply to the existing simple-cycle CTGs under permits N-2246-1-4 and N-2246-2-4. As discussed Section VIII.G.1 and VIII.G.2 of this PDOC, compliance is expected

Paragraph (b) states, *"The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine."* As discussed Section VIII.G.1 and VIII.G.2 of this PDOC, compliance is expected.

Paragraph (c)(2) states, "*Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent*" sulfur dioxide, the facility is required to submit a semiannual report to the District. As discussed Section VIII.G.4 of this PDOC such reporting will be required, and compliance is expected.

***§60.335: Test Methods and Procedures***

Paragraph (a) requires that the facility utilize methods approved by the Administrator to determine the nitrogen content of the fuel burned. As previously stated, the required annual NOx source test will be accepted in place of fuel nitrogen content testing. The EPA has delegated enforcement of subpart GG to the District and the District therefore has the authority to allow this.

Paragraph (b) requires that source testing be conducted utilizing the methods and procedures listed in 40 CFR Part 60 Appendix A or other methods listed in section GG. The appropriate source test methods will be determined as required by Subpart GG.

Paragraph (c)(1) requires that an ISO correction factor be applied to the observed NOx emission concentration. The ATC and the PTO will require that the ISO correction factor be applied.

## VIII. COMPLIANCE (Continued):

Paragraph (c)(2) states that the water-to-fuel ratio necessary to demonstrate compliance with the permitted $NO_x$ emission limits shall be determined at 30, 50, 75, and 100 percent of peak load or at four points in to normal operating range of the gas turbine, including the minimum point in the range and the peak load. The owner shall correct all loads to ISO standard conditions using appropriate equations supplier by the turbine manufacturer. This will only apply to the CTGs under permits N-2246-1-4 & N-2246-2-4.

Paragraph (c)(3) requires that EPA method 20 be utilized to determine the NOx emission, the SOx and stack $O_2$ content. §60.335(b) allows other source testing methods provided they are listed in 40 CFR part 60 Appendix A. EPA method 7E is listed in appendix A and will be allowed also.

Paragraph (d) lists the methods to be utilized to show compliance with §60.332(b). The ATCs will allow only the methods listed in this section.

***Rule 4002*** *National Emissions Standards for Hazardous Air Pollutants (NESHAP) (5/18/00)*

Pursuant to Section 2.0, "*All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;*" therefore, the requirements of this rule applies to the Walnut Energy Center. But there are no applicable requirements for a non-major HAPs source; therefore no actions are necessary to show compliance with this rule.

***Rule 4101*** *Visible Emissions (11/15/01)*

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour, which is as dark as or darker than Ringelmann 1 (or 20% opacity).

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-2246-2-4**

The CTGs lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement and the exhaust stack emissions will be limited by permit condition to no greater than 20% opacity except for three minutes in any hour. Therefore compliance is expected.

**N-2246-5-0**

The cooling tower is not expected to have visible emissions, excluding uncombined water vapor, greater than 20% opacity. Therefore, compliance is expected.

## VIII. COMPLIANCE (Continued):

**N-2246-5-0**

Under normal operating conditions, the visible emissions limit is not expected to be exceeded for the emergency IC engine, based on similar operations. Therefore, compliance is expected.

***Proposed Rule 4101 Conditions*:**

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-246-2-4**

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

**N-2246-5-0 and N-2246-6-0**

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

***Rule 4102*** *Nuisance (12/17/92)*

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, compliance with this rule is expected.

### A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

## VIII. COMPLIANCE (Continued):

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy TOX 1, TBACT is not required for any proposed emissions unit as shown in the table below:

| Screen HRA Summary | | | | |
|---|---|---|---|---|
| | Acute Hazard Index | Chronic Hazard Index | 70 yr Cancer Risk | T-BACT Required? |
| N-2246-1-4 (Turbine #1A) [15]<br>N-2246-2-4 (Turbine #2A)[15] | N/A | N/A | N/A | No |
| N-2246-3-0 (Turbine #1B)<br>N-2246-4-0 (Turbine #2B) | 0.03 | 0.0 | $4.26\times10^{-8}$ | No |
| N-2246-5-0 (Cooling Tower) | 0.01 | 0.03 | $6.73\times10^{-9}$ | No |
| N-2246-6-0 (Diesel Engine) | N/A | N/A | $7.77\times10^{-7}$ | No |
| Project Total | 0.69 | 0.00 | $\mathbf{8.26\times10^{-7}}$ | |

### B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

***<u>Proposed Rule 4102 Conditions</u>:***

**N-2246-3-0 and N-2246-4-0**

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**N-2246-1-4 and N-2246-2-4**

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**N-2246-5-0**

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

[15] Per District policy, HRAs are not required for modified emission units which do not result in an increase in emissions due to the proposed project. Since there will not be an increase in emissions due to the proposed modifications and HRA was not performed for these emission units.

## VIII. COMPLIANCE (Continued):

**N-2246-6-0**

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
- Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in this engine. [District Rule 2201 & 4102]
- $PM_{10}$ emission rate shall not exceed 0.09 g/hp-hr based on U.S EPA certification testing using test procedure ISO 8178. [District Rule 2201 & 4102]
- The exhaust stack shall not be fitted with a rain cap or similar device which would impede vertical exhaust flow. [District Rule 4102]
- The engine shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed 100 hours per year. [District Rule 2201 & 4102]

***Rule 4201*** *Particulate Matter Concentration (12/17/92)*

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

**N-2246-3-0 and N-2246-4-0**

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate) x (7000 gr/lb)}}{\text{(Air flow rate) x (60 min/hr)}}$$

$PM_{10}$ emission rate = 7.0 lb/hr. Assuming 100% of PM is $PM_{10}$
Exhaust Stack $H_2O$ Mass % = 4.77% (full load @ $61^0$F)
Exhaust Gas Flow, scfm (wet) = 687,130 ascfm
Exhaust Gas Flow, dscfm = 687,130 ascfm $\times$ [(100 – 4.77)/100] = 654,354 dscfm

PM Conc. (gr/scf) = [(7.0 lb/hr) $\times$ (7,000 gr/lb)] $\div$ [(654,354 dscf/min) $\times$ (60 min/hr)]
= 0.0012 gr/scf

**N-2246-5-0**

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate) x (7000 gr/lb)}}{\text{(Air flow rate) x (60 min/hr)}}$$

**VIII. COMPLIANCE (Continued):**

$PM_{10}$ emission rate = 1.3 lb/hr. Assuming 100% of PM is $PM_{10}$
Exhaust Gas Flow, scfm = 1,635,000 scfm

PM Conc. (gr/scf) = [(1.3 lb/hr) × (7,000 gr/lb)] ÷ [(1,635,000 scf/min) × (60 min/hr)]
= 0.000093 gr/scf

**N-2246-6-0**

The particulate matter concentration in the engine's exhaust stream can be estimated as follows:

$$PM\left(\frac{gr}{dscf}\right) = \frac{Emissions\left(\frac{gr-PM}{\text{min}}\right)}{Exhaust\ Flow\ (scfm)}$$

The applicant states that the exhaust flow rate is 304 dscfm at 738 °F. The particulate matter emission concentration at 60 °F is:

$$\text{PM}\left(\frac{\text{gr}}{\text{dscf}}\right) = \frac{0.01\frac{\text{lb}-\text{PM}}{\text{hr}}\times 7000\frac{\text{gr}-\text{PM}}{\text{lb}-\text{PM}}\times\frac{\text{hr}}{60\text{ min}}}{304\frac{\text{ft}^3}{\text{min}}\times\left(\frac{60+460}{738+460}\right)} = 0.009\frac{\text{gr}-\text{PM}}{\text{dscf}}$$

**N-2246-1-4 and N-2246-2-4**

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate) x (7000 gr/lb)}}{\text{(Air flow rate) x (60 min/hr)}}$$

$PM_{10}$ emission rate = 20.0 lb/hr. Assuming 100% of PM is $PM_{10}$ and utilizing fuel oil #2.
Exhaust Gas Flow, dscfm = 184,450 dscfm[16]

PM Conc. (gr/scf) = [(20.0 lb/hr) × (7,000 gr/lb)] ÷ [(184,450 dscf/min) × (60 min/hr)]
= 0.013 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all the permit units will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

[16] Lowest average dscfm exhaust flow rate from a source test conducted on 2/19/01.

## VIII. COMPLIANCE (Continued):

***Proposed Rule 4201 Condition:***

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

***Rule 4202*** *Particulate Matter Emission Rate (12/17/92)*

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the CTGs and the diesel fired I.C. engine. However, it does apply to the cooling tower.

**N-2246-5-0**

Weight rate/cooling tower = (68,500 gal/min $\times$ 60 min/hr $\times$ 8.34 lb/gal) $\div$ 2,000 lb/ton
= 17,139 ton/hr

Rule 4202 Emission Limit = 17.31 $\times$ $P^{0.16}$ (where P greater than 30 tons/hr)
= 17.31 $\times$ $(17{,}139 \text{ ton/hr})^{0.16}$
= 82.4 lb/hr

The cooling tower has a $PM_{10}$ emission rate of 1.3 lb/hr (30.8 lb/day @ 24 hr/day). All cooling tower PM emissions are $PM_{10}$. As shown above, the cooling tower PM emissions will be less than allowed by Rule 4202. Compliance is expected.

***Rule 4301*** *Fuel Burning Equipment (12/17/92)*

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-2246-2-4**

The CTGs primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTGs primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

**VIII. COMPLIANCE (Continued):**

**N-2246-6-0**

The emergency use IC engine produces power mechanically. Therefore, they do not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

***Rule 4701*** *Stationary Internal Combustion Engines (10/16/97)*

Pursuant to Section 4.2.1, emergency IC engines that do not operate more than 200 hours per year for non-emergency use are exempt from the requirements of this rule except for the recordkeeping requirements. Therefore, compliance with Rule 4701 is expected.

***Proposed Rule 4701 Conditions:***

**N-2246-6-0**

- The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 100 hours per year. [District Rules 2201 and 4701]

- The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be retained on site for a period of at least five years and made available for District inspection upon request. [District Rule 4701]

***Rule 4703*** *Stationary Gas Turbines (4/25/02)*

Rule 4703 limits $NO_X$ and CO emissions from stationary gas turbines with ratings of greater than 0.3 megawatts and/or maximum heat input ratings of more than 3,000,000 Btu/hr. The facility proposes to install two 84 MW gas turbines and currently operates two 25 MW gas turbines, therefore this rule applies.

NOx Limit:

**N-2246-3-0 and N-2246-4-0**

The Tier 2 NOx compliance limits specified in Table 5-2 are the most stringent. $NO_x$ emissions from the proposed gas turbine will be limited by permit condition to 2.0 ppmvd @ 15% $O_2$, which meets the enhanced requirement for combined cycle units rated greater than 10 MW. Therefore, compliance with the Tier 2 $NO_x$ emission concentration limit of this Rule is expected.

## VIII. COMPLIANCE (Continued):

Since Tier 2 NOx compliance limits are more stringent than Tier 1 NOx compliance limits, the proposed gas turbine is also expected to comply with the Tier 1 NOx compliance limits.

**N-2246-1-4 and N-2246-2-4**

The Tier 2 limits of section 5.1, state that simple-cycle stationary gas turbines rated greater than 10 MW and limited by permit condition for no greater than 877 hr/yr operation must comply with the following $NO_X$ limits:

- 25 ppmvd @ 15% $O_2$ for gaseous fuel
- 42 ppmvd @ 15% $O_2$ for liquid fuel

TID has proposed $NO_x$ emissions less than 25.0 ppmvd @ 15% $O_2$ for natural gas and less than 42 ppmvd @ 15% $O_2$ for fuel oil #2. Therefore, compliance with the Tier 2 $NO_x$ emission concentration limit of this Rule is expected. Since Tier 2 NOx compliance limits are more stringent than Tier 1 NOx compliance limits, the proposed gas turbine is also expected to comply with the Tier 1 NOx compliance limits.

<u>CO Limit:</u>

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-2246-2-4**

Per Table 5-3 of Section 5.2, the proposed gas turbines must be limited to a CO emission concentration of 200 ppmvd @ 15% $O_2$. The applicant is proposing a CO emission concentration limit of 4 ppmvd @ 15% $O_2$ for the two 84 MW gas turbines and 200 ppmvd @ 15% $O_2$ for the two 25MW gas turbines. Therefore, compliance with the CO emission concentration limit of this Rule is expected.

<u>Monitoring, Record Keeping, and Source Testing</u>:

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-2246-2-4**

Sections 6.2 and 6.3 contain the following monitoring, recordkeeping, and source testing requirements.

- 6.2.1 Except for units subject to Section 6.2.3, for turbines without exhaust-gas $NO_X$ control devices; install, operate, and maintain continuous emissions monitoring equipment for $NO_X$ and oxygen or install and maintain an APCO-approved alternate monitoring scheme.

**VIII. COMPLIANCE (Continued):**

- 6.2.2 Except for units subject to Section 6.2.3, for turbines without exhaust-gas $NO_X$ control devices and without continuous emissions monitoring equipment; monitor operational characteristics recommended by the turbine manufacturer or emission control system supplier, and approved by the APCO

- 6.2.3 Turbines rated at over 10 MW that operated an average of over 4,000 hours during the last three years before August 18, 1994, are required to install, operate, and maintain in calibration a continuous emissions monitoring system for $NO_X$. The applicant is proposing a CEMS for $NO_X$.

- 6.2.4 Maintain records for inspection at any time for a period of five years.

- 6.2.5 Correlate control system operating parameters with $NO_X$ emissions. This requirement applies to the selective catalytic reduction system. This information may be used by the APCO to determine compliance when the continuous emissions monitoring system not operating properly.

- 6.2.6 Maintain an operating log that includes, on a daily basis, the actual local start-up and stop time, length and reason for reduced load periods, total hours of operation, type and quantity of fuel used (liquid/gas).

- 6.3.1 Provide source test information annually regarding the exhaust gas $NO_X$ and CO concentrations, and, if used as a basis for Tier 1 emission limit calculations, the demonstrated percent efficiency (EFF) of the stationary gas turbines.

The facility must demonstrate compliance annually with the $NO_X$ and CO emission limits using the following test methods:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

**VIII. COMPLIANCE (Continued):**

These requirements will be included as permit conditions. Therefore, compliance with this rule is expected.

***<u>Proposed Rule 4703 Conditions</u>:***

**N-2246-3-0 and N-2246-4-0**

- Emission rates from this unit, except during startup and shutdown periods, shall not exceed any of the following: NOx (as NO2) 7.59 lb/hr and 2.0 ppmvd @ 15% O2; CO - 9.25 lb/hr and 4.0 ppmvd @ 15% O2; VOC (as methane) - 1.84 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 7.0 lb/hr; or SOx (as SO2) - 1.05 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

- The HRSG exhaust shall be equipped with continuous emission monitors (CEMs) for NOx, CO, and O2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F (for CO), and 40 CFR part 75 (for NOx and O2), and of the District-approved monitoring protocol, and shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 2201, 4001, and 4703]

- Source testing to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- The following test methods shall be used: PM10 - EPA Method 5 (front half and back half) or 201 and 202a, NOx - EPA Method 7E or 20, CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, ammonia - BAAQMD ST-1B, and fuel gas sulfur content - ASTM D3246. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

**VIII. COMPLIANCE (Continued):**

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

**N-2246-1-4 and N-2246-2-4**

- When firing on natural gas emission rates from this unit, except during thermal stabilization or reduced load periods as defined in District Rule 4703, shall not exceed any of the following: NOx (as NO2) 25 ppmvd @ 15% O2; CO 200 ppmvd @ 15% O2; VOC (as methane) - 15 lb/hr; PM10 – 8.6 lb/hr; or SOx (as SO2) – 0.00285 lb/MMBtu. Emission limits shall be average over a three-hour period, using 15-minute sampling periods. [District Rules 2201 and 4703]

- When firing on fuel oil #2 emission rates from this unit, except during thermal stabilization or reduced load periods as defined in District Rule 4703, shall not exceed any of the following: NOx (as NO2) 42 ppmvd @ 15% O2; CO 200 ppmvd @ 15% O2; VOC (as methane) - 15 lb/hr; PM10 – 20.0 lb/hr; or SOx (as SO2) – 16.38 lb/hr. Emission limits shall be average over a three-hour period, using 15-minute sampling periods. [District Rules 2201 and 4703]

- The operation of this unit shall not exceed 877 hours during any one year. [District Rule 4703]
- The sulfur content of fuel oil shall be less than 0.05 percent by weight. [District Rule 4703]

Section 6.2.2 requires the owner to monitor operational characteristics recommended by the turbine manufacturer or emission control system supplier. Section 6.2.5 requires the owner to submit to the District, prior to the issuance of a Permit to Operate, information correlating the control system operating parameters to the associated measured $NO_x$ emissions. The only emission control system employed on each turbine is a water injection system. §60.334 paragraph (a) requires owners or operators of any stationary gas turbine subject to this subpart and using water injection to control $NO_x$ emissions to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in each turbine. Therefore, following condition will be included on each permit:

## VIII. COMPLIANCE (Continued):

- The permittee shall monitor operational characteristics recommended by the turbine manufacturer or emission control supplier. Prior to the issuance of a Permit to Operate, the owner shall submit to the District information correlating the control system operating parameters to the associated measured NOx output. [District Rule 4703]

- The fuel consumption and the water-to-fuel ratio necessary to demonstrate compliance with the permitted $NO_x$ emission limits shall be determined and recorded at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and the peak load. The owner shall correct all loads to ISO standard conditions using appropriate equations supplier by the turbine manufacturer. [District Rule 4703 and 40 CFR 60.335(c)(2)]

- Source testing to demonstrate compliance with the NOx and CO emission limits for natural gas shall be conducted within 60 days of initial operation on that fuel. Source testing to demonstrate ongoing compliance with the NOx and CO emission limits for natural gas fuel shall be conducted at least once per 24-month period. [District Rules 2201 and 4703]

It is District practice for units whose primary fuel is natural gas to require source testing while firing on fuels other than natural gas only if each unit operates on fuels other than natural gas during a source testing period. District Rule 4703 requires source testing for stationary gas turbines operating less than 877 hr/yr at least once every 24 months. Therefore, the following condition will be included on each permit:

- Source testing to demonstrate compliance with the $NO_x$ and CO emission limits for fuel oil shall be conducted within 30 days of operation on that fuel, unless the unit successfully demonstrated compliance with the $NO_x$ and CO emission limits for fuel oil within the previous 24 months. [District Rules 2201 and 4703]

- The following test methods shall be used: NOx - EPA Method 7E or 20, CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, and fuel gas sulfur content - ASTM D3246. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703]

- The owner shall maintain a stationary gas turbine system operating log that includes: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation on each fuel, and type and quantity of each fuel used. These records shall be updated daily. [District Rules 2201 and 4703] N

## VIII. COMPLIANCE (Continued):

***Rule 4801*** *Sulfur Compounds (12/17/92)*

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as $SO_2$ on a dry basis averaged over 15 consecutive minutes.

**N-2246-3-0, N-2246-4-0, N-2246-1-4, and N-2246-2-4**

The worst case sulfur content of the natural gas fuel is 1.0 gr/100 dscf. This fuel sulfur content results in a SOx emission factor of 0.00285 lb/MMBtu. Rule 4801 limits sulfur compound emissions to 0.2% by volume, dry (2,000 ppmvd).

The ratio of the volume of the $SO_x$ exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of $SO_x$: $V = \dfrac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of $SO_x$ produced per MMBtu of fuel.
- Weight of $SO_x$ as $SO_2$ is 64 lb/(lb-mol)
- $n = \dfrac{0.00285\ lb}{MMBtu} \times \dfrac{1\ (lb - mol)}{64\ lb} = 0.000045\ (lb - mol)$
- $R = \dfrac{0.7302\, ft^3 \cdot atm}{(lb - mol\,)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SOx per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb\ -\ mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb\ -\ mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,710 scf, the ratio of $SO_X$ volume to exhaust volume is

$$= \frac{0.016}{8{,}710} = 0.0000018 = 1.8\ ppmv = 0.00018\,\%\ by\ volume$$

## VIII. COMPLIANCE (Continued):

1.8 ppmv ≤ 2000 ppmv, therefore the turbines are expected to comply with Rule 4801.

**N-2246-1-4, N-2246-2-4, and N-2246-6-0**

The maximum sulfur content of fuel oil #2 and diesel fuel utilized is 0.05% sulfur by weight.

$$0.05\%\ S \times \frac{7.1\ lb}{gal} \times \frac{64\ lb \cdot SO_2}{32\ lb \cdot S} \times \frac{1\ MMBtu}{9{,}051\ scf} \times \frac{1\ gal}{0.137\ MMBtu} \times \frac{lb \cdot mol}{64\ lb \cdot SO_2} \times \frac{10.73\ psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520\ °R}{14.7\ psi} = 33.9\ ppmv$$

Since 33.9 ppmv is ≤ 2000 ppmv, this engine is expected to comply with Rule 4801.

***Rule 7012*** *Hexavalent Chromium – Cooling Towers (12/17/92)*

The proposed cooling towers are new and will not use hexavalent chromium, therefore they meet the exemption criteria in section 4.1.2. Therefore, the cooling tower is exempt from the requirements of Rule 7012 except for sections 5.2.1, 6.1, and 7.1.

Section 5.2.1 requires that no hexavalent chromium compounds be added after 9/16/91 (intended to apply to cooling towers that previously used hexavalent chromium). A permit condition will be added to satisfy this requirement.

Section 6.1 requires that the owner/operator of a new cooling tower submit a compliance plan at least 90 days before it is operated containing business information, location of cooling tower, type and materials of construction, and a statement regarding the use or non use of hexavalent chromium. A permit condition will be added to satisfy this requirement.

Section 7.1 requires that the permittee pay permit filing fees associated with the cooling tower. WEC has paid such fees.

Compliance is expected.

***Proposed Rule 7012 Conditions:***

**N-2246-5-0**

- Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

- No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

**VIII. COMPLIANCE (Continued):**

***Rule 8011*** *General Requirements (11/15/01)*

The definitions, exemptions, requirements, administrative requirements, recordkeeping requirements, and test methods set forth in this rule are applicable to all rules under Regulation VIII (Fugitive PM10 Prohibitions) of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.

***Rule 8021*** *Construction, Demolition, Excavation, Extraction and Other Earthmoving* Activities *(11/15/01)*

The purpose of this rule is to limit fugitive dust emissions from construction, demolition, excavation, and other earthmoving activities. It requires the use of control measures to maintain visible dust emissions (VDE) under the 20% opacity requirement.

The WEC will commit to the use of dust control measures (e.g., water, approved chemical stabilizers, etc.) during construction to maintain opacity to a level below 20% per Rule 8021 requirements. Compliance with the requirements of this rule is anticipated.

***Proposed Rule 8021 Condition:***

- Disturbances of soil related to any construction, demolition, excavation, extraction, and other earthmoving activities shall comply with the requirements for fugitive dust control in SJVUAPCD District Rule 8021 (11/15/01) unless specifically exempted under section 4.0 of Rule 8021. [District Rule 8021]

***Rule 8031*** *Bulk Materials (11/15/01)*

Pursuant to Section 2.0, this rule is applicable to the outdoor handling, storage, and transport of any bulk material. The following condition will be included on the permit to satisfy the requirements of the rule.

***Proposed Rule 8031 Condition:***

- Outdoor handling, storage, and transport of any bulk material shall comply with the requirements of SJVUAPCD District Rule 8031 (11/15/01), unless specifically exempted under section 4.0 of Rule 8031. [District Rule 8031]

***Rule 8041*** *Carryout and Trackout (11/15/01)*

Pursuant to Section 2.0, this rule is applicable to all sites that are subject to Rule 8021 (Construction, Demolition, Excavation, Extraction, and other Earthmoving Activities), Rule 8031 (Bulk Materials), and Rule 8071 (Unpaved Vehicle and Equipment Traffic Areas) where carryout or trackout has occurred or may occur. The following condition will be included on the permit to satisfy the requirements of the rule.

## VIII. COMPLIANCE (Continued):

***Proposed Rule 8041 Condition:***

- All sites that are subject to SJVUAPCD District Rule 8021, SJVUAPCD District Rule 8031, and SJVUAPCD District Rule 8071 shall comply with the requirements of SJVUAPCD District Rule 8041 (11/15/01), unless specifically exempted under section 4.0 of Rule 8041. [District Rule 8041]

***Rule 8051*** *Open Areas (11/15/01)*

Pursuant to Section 2.0, this rule is applicable to any open area having 3.0 acres or more of disturbed surface area, that has remained undeveloped, unoccupied, unused or vacant for more than seven days. The following condition will be included on the permit to satisfy the requirements of the rule.

***Proposed Rule 8051 Condition:***

- Any open area having 3.0 acres or more of disturbed surface area, that has remained undeveloped, unoccupied, unused or vacant for more than seven days shall comply with the requirements of SJVUAPCD District Rule 8051 (11/15/01), unless specifically exempted under section 4.0 of Rule 8051. [District Rule 8051]

***Rule 8061*** *Paved and Unpaved Roads (11/15/01)*

Pursuant to Section 2.0, this rule applies to any new or existing public or private paved or unpaved road, road construction project, or road modification project. The following condition will be included on the permit to satisfy the requirements of the rule.

***Proposed Rule 8061 Condition:***

- Any new or existing public or private paved or unpaved road, road construction project, or road modification project shall implement the control measures and design criteria of, and comply with the requirements of SJVUAPCD District Rule 8061 (11/15/01) unless specifically exempted under section 4.0 of Rule 8061. [District Rule 8061] N

***Rule 8071*** *Unpaved Vehicle/Equipment Traffic Areas (11/15/01)*

Pursuant to Section 2.0, this rule applies to any unpaved vehicle/equipment traffic area of 1.0 acre or larger. The following condition will be included on the permit to satisfy the requirements of the rule.

**VIII. COMPLIANCE (Continued):**

***Proposed Rule 8071 Condition:***

- Any unpaved vehicle/equipment traffic area of 1.0 acre or larger shall comply with the requirements of SJVUAPCD District Rule 8071 (11/15/01), unless specifically exempted under section 4.0 of Rule 8071. [District Rule 8071]

***Rule 8081*** *Agricultural Sources (11/15/01)*

Pursuant to Section 2.0, this rule applies to off-field agricultural sources. The following condition will be included on the permit to satisfy the requirements of the rule.

***Proposed Rule 8081 Condition:***

- Any off-field agricultural sources shall comply with the requirements of SJVUAPCD District Rule 8081 (11/15/01), unless specifically exempted under section 4.0 of Rule 8081. [District Rule 8081]

**California Environmental Quality Act (CEQA)**

The California Energy Commission (CEC) is the lead Agency for CEQA. Generally, the District cannot make its final decision on ATCs until CEQA has been satisfied. For power generating projects that qualify for expedited processing (per District policy), the ATCs will be issued if the District's analysis and public notice is completed prior to CEQA approval. If the ATCs are issued prior to CEQA approval, the ATCs will include the following condition:

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

**California Health & Safety Code, Section 42301.6 (School Notice)**

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")**

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

## VIII. COMPLIANCE (Continued):

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

## IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Preliminary Determination of Compliance for the facility subject to the conditions presented in Attachment A.

## X. BILLING INFORMATION:

| Annual Permit Fees | | | |
|---|---|---|---|
| Permit Number | Fee Schedule | Fee Description | Annual Fee |
| N-2246-1-4 | 3020-08A-F | 25,800 kW[17] | $7,004.00 |
| N-2246-2-4 | 3020-08A-F | 25,800 kW[17] | $7,004.00 |
| N-2246-3-0 | 3020-08B-H | 134,000 kW[18] | $11,323.00 |
| N-2246-4-0 | 3020-08B-H | 134,000 kW[18] | $11,323.00 |
| N-2246-5-0 | 999-999 | Electrical Generation Component | $0.00 |
| N-2246-6-0 | 3020-10-C | 300 hp IC engine[19] | $205.00 |

Attachment A – PDOC Conditions
Attachment B – Project Location and Site Plan
Attachment C – Commissioning Period Emissions Data
Attachment D – CTG Emissions Data
Attachment E – SJVAPCD BACT Guidelines 3.4.2, 8.3.10, & 3.1.4.
Attachment F – Top Down BACT Analysis (N-2246-3-0 & N-2246-4-0)
Attachment G – Top Down BACT Analysis (N-2246-5-0)
Attachment H – Top Down BACT Analysis (N-2246-6-0)
Attachment I – Ambient Air Quality Analysis

[17] Previous fee schedule of 3020-08A-F based on 25,800 kW.
[18] Fee schedule is based on the combined total of the 84,000 kW gas turbine and the 50,000 kW steam turbine (half of the shared 100,000 kW steam turbine) for a total of 134,000 kW. In addition, there is not previous fee schedule for this permit unit.
[19] No previous fee schedule for this new permit unit.

Attachment J – Compliance Certification

# ATTACHMENT A

## *PDOC CONDITIONS*

**EQUIPMENT DESCRIPTION, UNIT N-2246-3-0:**
**84 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A 1,047 MMBTU/HR GENERAL ELECTRIC FRAME 7EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NOX COMBUSTOR, AN INLET AIR FILTRATION AND EVAPORATIVE COOLING SYSTEM, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) AND A 100 MW NOMINALLY RATED STEAM TURBINE SHARED WITH N-2246-4**

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001]

3. The heat recovery steam generator shall provide space for additional selective catalytic reduction catalyst and additional oxidation catalyst. The additional space shall be sufficient to house the quantity of catalyst material necessary to achieve and maintain compliance with the emission limits of this permit. [District Rule 2201]

4. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater except for up to three minutes in any hour. [District Rule 2201]

5. All equipment shall be maintained in proper operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

6. Prior to the issuance of the Permit to Operate, the permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

7. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. The gas turbine engine shall be fired exclusively on natural gas with a sulfur content of no greater than 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

11. Testing to demonstrate compliance with the fuel sulfur content limit of this permit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit of this permit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [District Rule 2201]

12. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

13. The permittee shall monitor and record the fuel flow rate to the turbine, NOx emission rate, the CO emission rate, the ammonia injection rate, the exhaust temperature both prior to and after the SCR unit, the exhaust oxygen content, and the exhaust flow rate. [District Rules 2201, 4001, and 4703]

14. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

15. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

16. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

17. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

18. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

19. The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

20. The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

21. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr or ppmvd emission limits for steady state operation. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown events shall not exceed 296 hours per calendar year. Startup emissions must be counted toward each applicable emission limit (lb/day and lb/yr). [District Rule 2201]

22. The cumulative startup and shutdown period duration shall not exceed five hours in any one day, commencing at midnight. Emissions during startup and shutdown periods must be counted toward the applicable daily emission limitations. [District Rule 2201]

23. The NOx emissions during start-up and shutdown periods shall not exceed 119.0 lb/hour. [District Rule 2201]

24. The NOx emissions concentration during steady state operation shall not exceed 2.0 ppmvd @ 15% O2 over a 1 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

25. The combined total NOx emissions from start-up, shut down, and steady state operation shall not exceed 444.2 lb/day. [District Rule 2201]

26. Compliance with NOx emission limitations during steady state operation shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15 minute periods designated by the owner/operator (and approved by the APCO) that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmvd @15% O2. The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmvd @ 15% O2. [District Rule 2201]

27. Examples of transient load conditions include, but are not limited to the following: (1) Initiation/shutdown of combustion turbine inlet air cooling and (2) Rapid combustion turbine load changes. All emissions during short-term excursions shall accrue towards the hourly, daily, and annual emissions limitations of this permit and shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit. [District Rule 2201]

28. The CO emissions during start-up and shutdown periods shall not exceed 129.0 lb/hour. [District Rule 2201]

29. The CO emissions concentration during steady state operation shall not exceed 4.0 ppmvd @ 15% O2 over a 3 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

30. The combined total CO emissions from start-up, shut down, and steady state operation shall not exceed 558.8 lb/day. [District Rule 2201]

31. The VOC emissions during start-up and shutdown periods shall not exceed 16.0 lb/hour. [District Rule 2201]

32. The VOC emissions concentration during steady state operation shall not exceed 1.4 ppmvd @ 15% O2 over a 3 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

33. The combined total VOC emissions from start-up, shut down, and steady state operation shall not exceed 83.0 lb/day. [District Rule 2201]

34. The PM10 emissions rate shall not exceed 7.0 lb/hr and 168.0 lb/day. [District Rule 2201] N

35. The SOx emission rate shall not exceed 1.05 lb/hr and 25.2 lb/day. [District Rule 2201] N

36. Ammonia (NH3) emissions concentration shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

37. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 4102]

38. The cumulative annual emissions shall not exceed 101,812 lb/year for CO and 17,404 lb/year for VOC. [District Rule 2201]

39. The cumulative quarterly NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 35,000 lb/quarter. [District Rule 2201]

40. The cumulative annual NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 140,000 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be complied from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. The twenty-four hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limit will be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] N

44. Source testing shall be witnessed or authorized by District personnel. [District Rule 1081] N

45. The results of each source test shall be received by the District no later than 60 days after the source test date. [District Rule 1081]

46. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-2246-3 or N-2246-4) prior to the end of the commissioning period and at least once every seven years, thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR Part 60, Appendix B. If CEM data is not certified to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 2201 and 4001]

47. Source testing to demonstrate compliance with the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), PM10 (lb/hr), and NH3 (ppmvd) emission limits and fuel gas sulfur content requirements shall be conducted within 60 days of initial operation. Source testing to demonstrate compliance with the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), PM10 (lb/hr), and NH3 (ppmvd) emission limits shall be conducted at least once every twelve months thereafter. [District Rule 2201 and 4001]

48. Source testing to determine the percent efficiency of the turbine shall be conducted annually. [District Rule 4703]

49. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E, EPA Method 20, or CARB method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 1081, 2201, 4001, and 4703]

50. VOC emissions (referenced as methane) shall be determined using EPA method 18 or EPA method 25. [District Rules 1081 and 2201]

51. CO emissions shall be determined using EPA method 10 or EPA method 10B. [District Rules 1081, 2201, and 4703]

52. Source testing to measure concentrations of PM10 shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. Alternative source testing methods will be allowed provided prior written approval is received from both the District and the EPA. [District Rules 1081 and 2201]

53. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081 and 4102]

54. Oxygen content of the exhaust gas shall be determined by using EPA method 3, EPA method 3A, or EPA method 20. [District Rules 1081, 2201, and 4703]

55. If necessary, testing for fuel sulfur content shall be conducted utilizing ASTM Method D 3246, ASTM Method D1072-90, ASTM Method D4468-85, ASTM Method D5504-94 or ASTM Method D3246-81. [District Rules 1081 and 4001]

56. Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703]

57. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 2201 and 4703]

58. The permittee shall maintain a daily record that includes the actual turbine start-up and stop times (local time), total hours of operation, and the quantity and type of fuel used. [District Rule 4703]

59. The permittee shall retain records of the cumulative annual NOx, CO, and VOC emissions. The record shall be updated daily. [District Rule 2201]

60. The permittee shall maintain hourly records of NOx, CO and ammonia concentrations (ppmv @ 15% O2). [District Rules 2201 and 4201]

61. The permittee shall submit a written report for each calendar quarter to the APCO. The report shall be received by the District within 30 days of the end of the quarter and shall include: time intervals and the magnitude of excess emissions, the nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard for the pollutant/source category in question; time and date of each period during which a continuous monitoring system was inoperative except for zero and span checks and the nature of system repairs and adjustments; a negative declaration when no excess emissions occurred. [District Rule 1080]

62. The permittee shall provide notification and record keeping as required under 40 CFR, Part 60, Subpart A, 60.7. [District Rule 4001]

63. Operator shall submit a semiannual report to the APCO listing any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeded 0.8% by weight. [District Rule 4001]

64. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]

65. Prior to operating equipment under this Authority to Construct, the permittee shall surrender NOx emission reduction credits for the following quantities of emissions: 1st quarter - 35,000 lb, 2nd quarter - 35,000 lb, 3rd quarter - 35,000 lb, and fourth quarter - 35,000 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

66. ERC Certificate Numbers C-482-2 and S-1834-2 shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

67. Prior to operating equipment under this Authority to Construct, the permittee shall surrender VOC emission reduction credits for the following quantities of emissions: 1st quarter - 13,053 lb, 2nd quarter - 13,053 lb, 3rd quarter - 13,053 lb, and fourth quarter - 13,053 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

68. ERC Certificate Numbers C-484-1 shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

69. Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits for the following quantities of emissions: 1st quarter - 36,104 lb, 2nd quarter - 36,104 lb, 3rd quarter - 36,104 lb, and fourth quarter - 36,104 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

70. ERC Certificate Numbers C-486-4, C-488-4, C-491-4, C-492-4, C-494-4, C-495-4, N-333-4, N-334-4, N-335-4, and N-336-4 shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

71. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

72. Permittee shall submit an application to comply with Rule 2540 (Acid Rain Program) at least 24 months prior to the date that the unit commences operation. [District Rule 2540]

73. Authority to Construct permits N-2246-3-0, N-2246-4-0, N-2246-5-0, N-2246-1-4, and N-2246-2-4 shall be implemented simultaneously. [District Rule 2201]

74. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

75. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

76. The owner/operator shall minimize the emissions from the gas turbine and heat recovery generator to the maximum extent possible during the commissioning period. Conditions 76 through 88 shall apply only during the commissioning period as defined below. [District Rule 2201]

77. Commissioning activities are defined as, but are not limited to, all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbines, heat recovery steam generator, steam turbine and associated electrical delivery systems. [District Rule 2201]

78. Commissioning period shall commence when all mechanical, electrical and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, is available for commercial operation. [District Rule 2201]

79. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

80. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted and operated to minimize emissions from the unit. [District Rule 2201]

81. Coincident with the steady state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in conditions #24 and #29, respectively. [District Rule 2201]

82. The owner/operator shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours and the purpose of the activity. The activities described shall include, but are not limited to the following: tuning of the combustors, installation and operation of the SCR systems and the oxidation catalyst, installation, calibration and testing of the NOx and CO continuous emission monitors and any activities requiring the firing of this unit without full abatement by the SCR system or oxidation catalyst. [District Rule 2201]

83. The emission rates during the commissioning period shall not exceed any of the following: NOx (as NO2) - 108.8 lb/hr, CO - 180.0 lb/hr, VOC (as methane) - 17.0 lb/hr, SOx - 0.94 lb/hr, and PM10 - 7.0 lb/hr. [District Rule 2201]

84. Only one of the turbines under permits N-2246-3 and N-2246-4 shall be operated at any one time without abatement and only during commissioning. Combined emission rates from permit units N-2246-3 and N-2246-4, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) - 227.8 lb/hr or 3,055.4 lb/day; CO - 309.0 lb/hr or 4,878.8 lb/day; VOC (as methane) - 33.0 lb/hr or 491 lb/day; SOx - 336.0 lb/day; PM10 - 47.8 lb/day. [District Rule 2201]

85. During the commissioning period, the permittee shall demonstrate compliance with conditions #83 and #84 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in these permit conditions. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the source is not in operation). [District Rule 2201]

86. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

87. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 288 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and unused balance of the 288 firing hours without abatement shall expire. [District Rule 2201]

88. The total mass emissions of NOx, CO and VOC that are emitted during the commissioning period shall accrue towards the annual emission limits specified in conditions #38 and #40. [District Rule 2201]

89. Disturbances of soil related to any construction, demolition, excavation, extraction, and other earthmoving activities shall comply with the requirements for fugitive dust control in SJVAPCD District Rule 8021 (11/05/01) unless specifically exempted under section 4.0 of Rule 8021. [District Rule 8021]

90. Outdoor handling, storage, and transport of any bulk material shall comply with the requirements of SJVAPCD District Rule 8031 (11/15/01), unless specifically exempted under section 4.0 of Rule 8031. [District Rule 8031]

91. All sites that are subject to SJVAPCD District Rule 8021, SJVAPCD District Rule 8031, and SJVAPCD District Rule 8071 shall comply with the requirements of SJVAPCD District Rule 8041 (11/15/01), unless specifically exempted under section 4.0 of Rule 8041. [District Rule 8041]

92. Any open area having 3.0 acres or more of disturbed surface area, that has remained undeveloped, unoccupied, unused or vacant for more than seven days shall comply with the requirements of SJVAPCD District Rule 8051 (11/15/01), unless specifically exempted under section 4.0 of Rule 8051. [District Rule 8051]

93. Any new or existing public or private paved or unpaved road, road construction project, or road modification project shall implement the control measures and design criteria of, and comply with the requirements of SJVAPCD District Rule 8061 (11/15/01) unless specifically exempted under section 4.0 of Rule 8061. [District Rule 8061]

94. Any unpaved vehicle/equipment traffic area of 1.0 acre or larger shall comply with the requirements of SJVAPCD District Rule 8071 (11/15/01), unless specifically exempted under section 4.0 of Rule 8071. [District Rule 8071]

95. Any off-field agricultural sources shall comply with the requirements of SJVAPCD District Rule 8081 (11/15/01), unless specifically exempted under section 4.0 of Rule 8081. [District Rule 8081]

**EQUIPMENT DESCRIPTION, UNIT N-2246-4-0:**
**84 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A 1,047 MMBTU/HR GENERAL ELECTRIC FRAME 7EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NOX COMBUSTOR, AN INLET AIR FILTRATION AND EVAPORATIVE COOLING SYSTEM, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) AND A 100 MW NOMINALLY RATED STEAM TURBINE SHARED WITH N-2246-3**

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001]

3. The heat recovery steam generator shall provide space for additional selective catalytic reduction catalyst and additional oxidation catalyst. The additional space shall be sufficient to house the quantity of catalyst material necessary to achieve and maintain compliance with the emission limits of this permit. [District Rule 2201]

4. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater except for up to three minutes in any hour. [District Rule 2201]

5. All equipment shall be maintained in proper operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

6. Prior to the issuance of the Permit to Operate, the permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

7. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

10. The gas turbine engine shall be fired exclusively on natural gas with a sulfur content of no greater than 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

11. Testing to demonstrate compliance with the fuel sulfur content limit of this permit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit of this permit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [District Rule 2201]

12. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

13. The permittee shall monitor and record the fuel flow rate to the turbine, NOx emission rate, the CO emission rate, the ammonia injection rate, the exhaust temperature both prior to and after the SCR unit, the exhaust oxygen content, and the exhaust flow rate. [District Rules 2201, 4001, and 4703]

14. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

15. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

16. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

17. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

18. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

19. The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

20. The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

21. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr or ppmvd emission limits for steady state operation. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown events shall not exceed 296 hours per calendar year. Startup emissions must be counted toward each applicable emission limit (lb/day and lb/yr). [District Rule 2201]

22. The cumulative startup and shutdown period duration shall not exceed five hours in any one day, commencing at midnight. Emissions during startup and shutdown periods must be counted toward the applicable daily emission limitations. [District Rule 2201]

23. The NOx emissions during start-up and shutdown periods shall not exceed 119.0 lb/hour. [District Rule 2201]

24. The NOx emissions concentration during steady state operation shall not exceed 2.0 ppmvd @ 15% O2 over a 1 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

25. The combined total NOx emissions from start-up, shut down, and steady state operation shall not exceed 444.2 lb/day. [District Rule 2201]

26. Compliance with NOx emission limitations during steady state operation shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15 minute periods designated by the owner/operator (and approved by the APCO) that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmvd @15% O2. The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmvd @ 15% O2. [District Rule 2201]

27. Examples of transient load conditions include, but are not limited to the following: (1) Initiation/shutdown of combustion turbine inlet air cooling and (2) Rapid combustion turbine load changes. All emissions during short-term excursions shall accrue towards the hourly, daily, and annual emissions limitations of this permit and shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit. [District Rule 2201]

28. The CO emissions during start-up and shutdown periods shall not exceed 129.0 lb/hour. [District Rule 2201]

29. The CO emissions concentration during steady state operation shall not exceed 4.0 ppmvd @ 15% O2 over a 3 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

30. The combined total CO emissions from start-up, shut down, and steady state operation shall not exceed 558.8 lb/day. [District Rule 2201]

31. The VOC emissions during start-up and shutdown periods shall not exceed 16.0 lb/hour. [District Rule 2201]

32. The VOC emissions concentration during steady state operation shall not exceed 1.4 ppmvd @ 15% O2 over a 3 hour rolling average. Steady-state period refers to any periods that is not a start-up or shut down period. [District Rule 2201]

33. The combined total VOC emissions from start-up, shut down, and steady state operation shall not exceed 83.0 lb/day. [District Rule 2201]

34. The PM10 emissions rate shall not exceed 7.0 lb/hr and 168.0 lb/day. [District Rule 2201] N

35. The SOx emission rate shall not exceed 1.05 lb/hr and 25.2 lb/day. [District Rule 2201] N

36. Ammonia (NH3) emissions concentration shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

37. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 4102]

38. The cumulative annual emissions shall not exceed 101,812 lb/year for CO and 17,404 lb/year for VOC. [District Rule 2201]

39. The cumulative quarterly NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 35,000 lb/quarter. [District Rule 2201]

40. The cumulative annual NOx emissions from permit units N-2246-3 and N-2246-4 shall not exceed 140,000 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be complied from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. The twenty-four hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limit will be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] N

44. Source testing shall be witnessed or authorized by District personnel. [District Rule 1081] N

45. The results of each source test shall be received by the District no later than 60 days after the source test date. [District Rule 1081]

46. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-2246-3 or N-2246-4) prior to the end of the commissioning period and at least once every seven years, thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR Part 60, Appendix B. If CEM data is not certified to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 2201 and 4001]

47. Source testing to demonstrate compliance with the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), PM10 (lb/hour), and NH3 (ppmvd) emission limits and fuel gas sulfur content requirements shall be conducted within 60 days of initial operation. Source testing to demonstrate compliance with the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), PM10 (lb/hour), and NH3 (ppmvd) emission limits shall be conducted at least once every twelve months thereafter. [District Rule 2201 and 4001]

48. Source testing to determine the percent efficiency of the turbine shall be conducted annually. [District Rule 4703]

49. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E, EPA Method 20, or CARB method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 1081, 2201, 4001, and 4703]

50. VOC emissions (referenced as methane) shall be determined using EPA method 18 or EPA method 25. [District Rules 1081 and 2201]

51. CO emissions shall be determined using EPA method 10 or EPA method 10B. [District Rules 1081, 2201, and 4703]

52. Source testing to measure concentrations of PM10 shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. Alternative source testing methods will be allowed provided prior written approval is received from both the District and the EPA. [District Rules 1081 and 2201]

53. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081 and 4102]

54. Oxygen content of the exhaust gas shall be determined by using EPA method 3, EPA method 3A, or EPA method 20. [District Rules 1081, 2201, and 4703]

55. If necessary, testing for fuel sulfur content shall be conducted utilizing ASTM Method D 3246, ASTM Method D1072-90, ASTM Method D4468-85, ASTM Method D5504-94 or ASTM Method D3246-81. [District Rules 1081 and 4001]

56. Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703]

57. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 2201 and 4703]

58. The permittee shall maintain a daily record that includes the actual turbine start-up and stop times (local time), total hours of operation, and the quantity and type of fuel used. [District Rule 4703]

59. The permittee shall retain records of the cumulative annual NOx, CO, and VOC emissions. The record shall be updated daily. [District Rule 2201]

60. The permittee shall maintain hourly records of NOx, CO and ammonia concentrations (ppmv @ 15% O2). [District Rules 2201 and 4201]

61. The permittee shall submit a written report for each calendar quarter to the APCO. The report shall be received by the District within 30 days of the end of the quarter and shall include: time intervals and the magnitude of excess emissions, the nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard for the pollutant/source category in question; time and date of each period during which a continuous monitoring system was inoperative except for zero and span checks and the nature of system repairs and adjustments; a negative declaration when no excess emissions occurred. [District Rule 1080]

62. The permittee shall provide notification and record keeping as required under 40 CFR, Part 60, Subpart A, 60.7. [District Rule 4001]

63. Operator shall submit a semiannual report to the APCO listing any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeded 0.8% by weight. [District Rule 4001]

64. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]

65. Prior to operating equipment under this Authority to Construct, the permittee shall surrender NOx emission reduction credits for the following quantities of emissions: 1st quarter - 35,000 lb, 2nd quarter - 35,000 lb, 3rd quarter - 35,000 lb, and fourth quarter - 35,000 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

66. ERC Certificate Numbers C-482-2 and S-1834-2 shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

67. Prior to operating equipment under this Authority to Construct, the permittee shall surrender VOC emission reduction credits for the following quantities of emissions: 1st quarter - 13,053 lb, 2nd quarter - 13,053 lb, 3rd quarter - 13,053 lb, and fourth quarter - 13,053 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

68. ERC Certificate Numbers C-484-1 shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

69. Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits for the following quantities of emissions: 1st quarter - 36,104 lb, 2nd quarter - 36,104 lb, 3rd quarter - 36,104 lb, and fourth quarter - 36,104 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

70. ERC Certificate Numbers C-486-4, C-488-4, C-491-4, C-492-4, C-494-4, C-495-4, N-333-4, N-334-4, N-335-4, and N-336-4 shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

71. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

72. Permittee shall submit an application to comply with Rule 2540 (Acid Rain Program) at least 24 months prior to the date that the unit commences operation. [District Rule 2540]

73. Authority to Construct permits N-2246-3-0, N-2246-4-0, N-2246-5-0, N-2246-1-4, and N-2246-2-4 shall be implemented simultaneously. [District Rule 2201]

74. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

75. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

76. The owner/operator shall minimize the emissions from the gas turbine and heat recovery generator to the maximum extent possible during the commissioning period. Conditions 76 through 88 shall apply only during the commissioning period as defined below. [District Rule 2201]

77. Commissioning activities are defined as, but are not limited to, all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbines, heat recovery steam generator, steam turbine and associated electrical delivery systems. [District Rule 2201]

78. Commissioning period shall commence when all mechanical, electrical and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, is available for commercial operation. [District Rule 2201]

79. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

80. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted and operated to minimize emissions from the unit. [District Rule 2201]

81. Coincident with the steady state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in conditions #24 and #29, respectively. [District Rule 2201]

82. The owner/operator shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours and the purpose of the activity. The activities described shall include, but are not limited to the following: tuning of the combustors, installation and operation of the SCR systems and the oxidation catalyst, installation, calibration and testing of the NOx and CO continuous emission monitors and any activities requiring the firing of this unit without full abatement by the SCR system or oxidation catalyst. [District Rule 2201]

83. The emission rates during the commissioning period shall not exceed any of the following: NOx (as NO2) - 108.8 lb/hr, CO - 180.0 lb/hr, VOC (as methane) - 17.0 lb/hr, SOx - 0.94 lb/hr, and PM10 - 7.0 lb/hr. [District Rule 2201]

84. Only one of the turbines under permits N-2246-3 and N-2246-4 shall be operated at any one time without abatement and only during commissioning. Combined emission rates from permit units N-2246-3 and N-2246-4, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) - 227.8 lb/hr or 3,055.4 lb/day; CO - 309.0 lb/hr or 4,878.8 lb/day; VOC (as methane) - 33.0 lb/hr or 491 lb/day; SOx - 336.0 lb/day; PM10 - 47.8 lb/day. [District Rule 2201]

85. During the commissioning period, the permittee shall demonstrate compliance with conditions #83 and #84 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in these permit conditions. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the source is not in operation). [District Rule 2201]

86. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

87. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 288 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and unused balance of the 288 firing hours without abatement shall expire. [District Rule 2201]

88. The total mass emissions of NOx, CO and VOC that are emitted during the commissioning period shall accrue towards the annual emission limits specified in conditions #38 and #40. [District Rule 2201]

89. Disturbances of soil related to any construction, demolition, excavation, extraction, and other earthmoving activities shall comply with the requirements for fugitive dust control in SJVAPCD District Rule 8021 (11/05/01) unless specifically exempted under section 4.0 of Rule 8021. [District Rule 8021]

90. Outdoor handling, storage, and transport of any bulk material shall comply with the requirements of SJVAPCD District Rule 8031 (11/15/01), unless specifically exempted under section 4.0 of Rule 8031. [District Rule 8031]

91. All sites that are subject to SJVAPCD District Rule 8021, SJVAPCD District Rule 8031, and SJVAPCD District Rule 8071 shall comply with the requirements of SJVAPCD District Rule 8041 (11/15/01), unless specifically exempted under section 4.0 of Rule 8041. [District Rule 8041]

92. Any open area having 3.0 acres or more of disturbed surface area, that has remained undeveloped, unoccupied, unused or vacant for more than seven days shall comply with the requirements of SJVAPCD District Rule 8051 (11/15/01), unless specifically exempted under section 4.0 of Rule 8051. [District Rule 8051]

93. Any new or existing public or private paved or unpaved road, road construction project, or road modification project shall implement the control measures and design criteria of, and comply with the requirements of SJVAPCD District Rule 8061 (11/15/01) unless specifically exempted under section 4.0 of Rule 8061. [District Rule 8061]

94. Any unpaved vehicle/equipment traffic area of 1.0 acre or larger shall comply with the requirements of SJVAPCD District Rule 8071 (11/15/01), unless specifically exempted under section 4.0 of Rule 8071. [District Rule 8071]

95. Any off-field agricultural sources shall comply with the requirements of SJVAPCD District Rule 8081 (11/15/01), unless specifically exempted under section 4.0 of Rule 8081. [District Rule 8081]

**EQUIPMENT DESCRIPTION, UNIT N-2246-5-0:**
**68,500 GPM MECHANICAL DRAFT COOLING TOWER WITH 5 CELLS SERVED BY A HIGH EFFICIENCY DRIFT ELIMINATOR**

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

3. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule]

6. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

7. Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

8. The PM10 emissions shall not exceed 30.8 lb/day. [District Rule 2201]

9. Compliance with the PM10 emission limit shall be demonstrated as follows: PM10 lb/day = Circulating Water Recirculation rate (gal/day) x 8.34 lb/gal x Total Dissolved Solids Concentration in the blowdown water (ppm) x Design Drift Rate (%). [District Rule 2201]

10. Compliance with PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 60 days of initial operation and quarterly, thereafter. [District Rule 1081]

11. Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits for the following quantities of emissions: 1st quarter - 36,104 lb, 2nd quarter - 36,104 lb, 3rd quarter - 36,104 lb, and fourth quarter - 36,104 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/25/02). [District Rule 2201]

12. ERC Certificate Numbers C-486-4, C-488-4, C-491-4, C-492-4, C-494-4, C-495-4, N-333-4, N-334-4, N-335-4, and N-336-4 shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct [District Rule 2201]

13. Authority to Construct permits N-2246-3-0, N-2246-4-0, N-2246-5-0, N-2246-1-4, and N-2246-2-4 shall be implemented simultaneously. [District Rule 2201]

14. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

**EQUIPMENT DESCRIPTION, UNIT N-2246-5-0:**
**300 HP JOHN DEERE COMPANY MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP.**

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule]

3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

5. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. The exhaust stack shall not be fitted with a rain cap, or any other similar device, that impedes upward vertical exhaust flow. [District Rule 4102]

7. The NOx emissions from the engine shall not exceed 5.2 grams/hp-hr. [District Rule 2201]

8. The CO emissions from the engine shall not exceed 0.27 grams/hp-hr. [District Rule 2201]

9. The VOC emissions from the engine shall not exceed 0.15 grams/hp-hr. [District Rule 2201]

10. The PM10 emissions from the engine shall not exceed 0.09 grams/hp-hr based on U.S EPA certification testing using test procedure ISO 8178. [District Rules 2201 & 4102]

11. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in this engine. [District Rules 2201 & 4102]

12. The engine shall be operated only for maintenance, testing, required regulatory purposes and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 100 hours per year. [District Rules 2201 & 4102]

13. The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be made available for District inspection upon request for a period of five years. [District Rule 1070]

14. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

**EQUIPMENT DESCRIPTION, UNIT N-2246-1-4:**
**MODIFICATION OF THE 25.8 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A 325 MMBTU/HR GENERAL ELECTRIC MODEL PG 5361 FRAME 5 NATURAL GAS/FUEL OIL #2 FIRED TURBINE GENERATOR WITH WATER INJECTION TO LIMIT THE ANNUAL PM10 EMISSIONS TO 7,016 POUNDS.**

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

2. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

3. This unit is subject to the requirements of 40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. [District Rule 4001]

4. A continuous monitoring system shall be installed and operated to measure and record the fuel consumption and the mass ratio of water-to-fuel injected into the combustors. [40 CFR 60.334(a)]

5. The owner shall monitor operational characteristics recommended by the turbine manufacturer or emission control system supplier. Prior to the issuance of a Permit to Operate, the owner shall submit to the District information correlating the control system operating parameters to the associated measured NOx output. [District Rule 4703]

6. This unit shall be fired on only natural gas or fuel oil #2. The primary fuel shall be natural gas; fuel oil #2 shall be used as a backup fuel only in the event of a natural gas shortage. [District Rule 2201]

7. This unit shall be fired only on natural gas with a sulfur content not exceeding 1.0 grain of sulfur compounds (as S) per 100 dry standard cubic feet of natural gas. If this is fired on PUC-regulated natural gas, compliance with this sulfur content limit may be demonstrated with fuel receipts. [District Rule 2201]

8. If this unit is not fired on PUC-regulated natural gas, the sulfur content of each fuel source shall be tested weekly except that if compliance with the fuel sulfur content limit has been demonstrated for eight consecutive weeks for a fuel source, then the testing frequency shall be quarterly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until compliance is demonstrated for eight consecutive weeks. [40 CFR 60.334(b)(2)]

9. The sulfur content of fuel oil shall be less than 0.05 percent by weight. [District Rule 4703]

10. The sulfur content of the fuel oil shall be determined each time fuel is transferred into the on-site storage tank. [40 CFR 60.334(b)(1)]

11. The operation of this unit shall not exceed 877 hours during any one year. [District Rule 4703]

12. When firing on natural gas, NOx (referenced as NO2) emissions shall not exceed 25.0 ppmvd @ 15% O2, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

13. When firing on fuel oil, the NOx (referenced as NO2) emissions shall not exceed 42.0 ppmvd @ 15% O2 and 51 lb/hr, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

14. The NOx emission concentration shall not exceed 42 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703, and the NOx emission rate shall not exceed 51 pounds in any one hour. [District Rules 2201 and 4703]

15. The combined NOx emissions from permit units N-2246-1 and N-2246-2 shall not exceed 1,020 lb/day and shall not exceed 25,551 lb/quarter. [District Rule 2201]

16. When firing on either natural gas or fuel oil, CO emissions shall not exceed 200 ppmvd @ 15% O2, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

17. When firing on either natural gas or fuel oil, VOC emissions shall not exceed 15.00 lb/hr. [District Rule 2201]

18. When firing on natural gas, PM10 emissions shall not exceed 8.60 lb/hr. [District Rule 2201]

19. When firing on fuel oil, PM10 emissions shall not exceed 20.00 lb/hr. [District Rule 2201]

20. The combined PM10 emissions from permit units N-2246-1 and N-2246-2 shall not exceed 150 pounds during any one day. [District Rule 2201]

21. The annual PM10 emissions shall not exceed 7,016 lb/year. [District Rule 2201]

22. When firing on natural gas, SOx emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]

23. When firing on fuel oil, SOx emissions shall not exceed 16.37 lb/hr. [District Rule 2201]

24. In the event of a natural gas shortage, SOx emissions from permit units N-2246-1 and N-2246-2 shall not exceed 5,950 pounds during any one month. [District Rule 2201]

25. Source testing to demonstrate initial compliance with the NOx and CO emission limits for natural gas shall be conducted within 60 days of initial operation on that fuel. Source testing to demonstrate ongoing compliance with the NOx and CO emission limits for natural gas fuel shall be conducted at least once per 24-month period. [District Rules 2201 and 4703]

26. Source testing to demonstrate compliance with the NOx and CO emission limits for fuel oil shall be conducted within 30 days of operation on that fuel, unless the unit successfully demonstrated compliance with the NOx and CO emission limits for fuel oil within the previous 24 months. [District Rules 2201 and 4703]

27. The fuel consumption and the water-to-fuel ratio necessary to demonstrate compliance with the permitted NOx emission limits shall be determined and recorded at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and the peak load. The owner shall correct all loads to ISO standard conditions using appropriate equations supplier by the turbine manufacturer. [District Rule 4703 and 40 CFR 60.335(c)(2)]

28. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

29. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

30. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

31. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 1081, 4001, and 4703]

32. CO emissions shall be determined using EPA method 10 or EPA method 10B. [District Rules 1081 and 4703]

33. Oxygen content of the exhaust gas shall be determined by using EPA method 3, EPA method 3A, or EPA method 20. [District Rules 1081 and 4703]

34. The owner shall maintain a stationary gas turbine system operating log that includes: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation on each fuel, and type and quantity of each fuel used. These records shall be updated daily. [District Rules 2201 and 4703]

35. The owner shall maintain a log that shows the following: (a). The combined daily NOx emissions from permit units N-2246-1 and N-2246-2; (b). The combined daily PM10 emissions from permit units N-2246-1 and N-2246-2; (c). The cumulative quarterly NOx emissions from permit units N-2246-1 and N-2246-2; (d) The cumulative annual PM10 emissions from this permit unit (N-2246-1). This log shall contain each calculated emission quantity as well as each process variable used in the respective calculations. [District Rule 2201]

36. All records shall be retained for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 2201 and 4703]

37. Authority to Construct permits N-2246-3-0, N-2246-4-0, N-2246-5-0, N-2246-1-4, and N-2246-2-4 shall be implemented simultaneously. [District Rule 2201]

**<u>EQUIPMENT DESCRIPTION, UNIT N-2246-2-4</u>:**
**MODIFICATION OF THE 25.8 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A 325 MMBTU/HR GENERAL ELECTRIC MODEL PG 5361 FRAME 5 NATURAL GAS/FUEL OIL #2 FIRED TURBINE GENERATOR WITH WATER INJECTION TO LIMIT THE ANNUAL PM10 EMISSIONS TO 7,016 POUNDS.**

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

2. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

3. This unit is subject to the requirements of 40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. [District Rule 4001]

4. A continuous monitoring system shall be installed and operated to measure and record the fuel consumption and the mass ratio of water-to-fuel injected into the combustors. [40 CFR 60.334(a)]

5. The owner shall monitor operational characteristics recommended by the turbine manufacturer or emission control system supplier. Prior to the issuance of a Permit to Operate, the owner shall submit to the District information correlating the control system operating parameters to the associated measured NOx output. [District Rule 4703]

6. This unit shall be fired on only natural gas or fuel oil #2. The primary fuel shall be natural gas; fuel oil #2 shall be used as a backup fuel only in the event of a natural gas shortage. [District Rule 2201]

7. This unit shall be fired only on natural gas with a sulfur content not exceeding 1.0 grain of sulfur compounds (as S) per 100 dry standard cubic feet of natural gas. If this is fired on PUC-regulated natural gas, compliance with this sulfur content limit may be demonstrated with fuel receipts. [District Rule 2201]

8. If this unit is not fired on PUC-regulated natural gas, the sulfur content of each fuel source shall be tested weekly except that if compliance with the fuel sulfur content limit has been demonstrated for eight consecutive weeks for a fuel source, then the testing frequency shall be quarterly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until compliance is demonstrated for eight consecutive weeks. [40 CFR 60.334(b)(2)]

9. The sulfur content of fuel oil shall be less than 0.05 percent by weight. [District Rule 4703]

10. The sulfur content of the fuel oil shall be determined each time fuel is transferred into the on-site storage tank. [40 CFR 60.334(b)(1)]

11. The operation of this unit shall not exceed 877 hours during any one year. [District Rule 4703]

12. When firing on natural gas, NOx (referenced as NO2) emissions shall not exceed 25.0 ppmvd @ 15% O2, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

13. When firing on fuel oil, the NOx (referenced as NO2) emissions shall not exceed 42.0 ppmvd @ 15% O2 and 51 lb/hr, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

14. The NOx emission concentration shall not exceed 42 ppmvd @ 15% O2 except for thermal stabilization or reduced load period, as defined in Rule 4703, and the NOx emission rate shall not exceed 51 pounds in any one hour. [District Rules 2201 and 4703]

15. The combined NOx emissions from permit units N-2246-1 and N-2246-2 shall not exceed 1,020 lb/day and shall not exceed 25,551 lb/quarter. [District Rule 2201]

16. When firing on either natural gas or fuel oil, CO emissions shall not exceed 200 ppmvd @ 15% O2, except during thermal stabilization or reduced load period as defined in District Rule 4703. Emissions shall be averaged over a three-hour period, using consecutive 15-minute sampling periods. [District Rules 2201 and 4703]

17. When firing on either natural gas or fuel oil, VOC emissions shall not exceed 15.00 lb/hr. [District Rule 2201]

18. When firing on natural gas, PM10 emissions shall not exceed 8.60 lb/hr. [District Rule 2201]

19. When firing on fuel oil, PM10 emissions shall not exceed 20.00 lb/hr. [District Rule 2201]

20. The combined PM10 emissions from permit units N-2246-1 and N-2246-2 shall not exceed 150 pounds during any one day. [District Rule 2201]

21. The annual PM10 emissions shall not exceed 7,016 lb/year. [District Rule 2201]

22. When firing on natural gas, SOx emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]

23. When firing on fuel oil, SOx emissions shall not exceed 16.37 lb/hr. [District Rule 2201]

24. In the event of a natural gas shortage, SOx emissions from permit units N-2246-1 and N-2246-2 shall not exceed 5,950 pounds during any one month. [District Rule 2201]

25. Source testing to demonstrate initial compliance with the NOx and CO emission limits for natural gas shall be conducted within 60 days of initial operation on that fuel. Source testing to demonstrate ongoing compliance with the NOx and CO emission limits for natural gas fuel shall be conducted at least once per 24-month period. [District Rules 2201 and 4703]

26. Source testing to demonstrate compliance with the NOx and CO emission limits for fuel oil shall be conducted within 30 days of operation on that fuel, unless the unit successfully demonstrated compliance with the NOx and CO emission limits for fuel oil within the previous 24 months. [District Rules 2201 and 4703]

27. The fuel consumption and the water-to-fuel ratio necessary to demonstrate compliance with the permitted NOx emission limits shall be determined and recorded at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and the peak load. The owner shall correct all loads to ISO standard conditions using appropriate equations supplier by the turbine manufacturer. [District Rule 4703 and 40 CFR 60.335(c)(2)]

28. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

29. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

30. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

31. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 1081, 4001, and 4703]

32. CO emissions shall be determined using EPA method 10 or EPA method 10B. [District Rules 1081 and 4703]

33. Oxygen content of the exhaust gas shall be determined by using EPA method 3, EPA method 3A, or EPA method 20. [District Rules 1081 and 4703]

34. The owner shall maintain a stationary gas turbine system operating log that includes: the actual local start-up and stop time; length and reason for reduced load periods; total hours of operation on each fuel, and type and quantity of each fuel used. These records shall be updated daily. [District Rules 2201 and 4703]

35. The owner shall maintain a log that shows the following: (a). The combined daily NOx emissions from permit units N-2246-1 and N-2246-2; (b). The combined daily PM10 emissions from permit units N-2246-1 and N-2246-2; (c). The cumulative quarterly NOx emissions from permit units N-2246-1 and N-2246-2; (d) The cumulative annual PM10 emissions from this permit unit (N-2246-2). This log shall contain each calculated emission quantity as well as each process variable used in the respective calculations. [District Rule 2201]

36. All records shall be retained for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 2201 and 4703]

37. Authority to Construct permits N-2246-3-0, N-2246-4-0, N-2246-5-0, N-2246-1-4, and N-2246-2-4 shall be implemented simultaneously. [District Rule 2201]

# ATTACHMENT B

## *Project Location and Site Plan*

# ATTACHMENT C

## *Commissioning Period Emissions Data*

# ATTACHMENT D

## _CTG Emissions Data_

# ATTACHMENT E

## *SJVAPCD BACT GUIDELINES 3.4.2, 8.3.10, & 3.1.4*

# ATTACHMENT F

## *TOP DOWN BACT ANALYSIS*
## *(N-2246-3-0 & N-2246-4-0)*

**1. BACT Applicability:**

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, or $SO_X$. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

As seen in Section VIII.A.1 of this evaluation, the applicant is proposing to install new emissions units with PEs greater than 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$. BACT is triggered for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$ criteria pollutants since the PEs are greater than 2 lb/day, and since the SSPE2 for CO is greater than 200,000 lb/year, as demonstrated in Section VII.C.6 of this document.

**2. BACT Guidance:**

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse includes BACT Guideline (3.4.2) applicable to the two combustion turbine generator installations [Gas Fired Turbine ≥ to 374 MMBtu/hr, Uniform Load, with Heat Recovery]. (See Attachment C)

**3. Top-Down BACT Analysis:**

**A. $NO_X$ Top-Down BACT Analysis for Permits N-2246-3-0 and N-2246-4-0**

According to BACT guideline 3.4.2 (Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery), the following are possible controls for $NO_X$ emissions from similar operations.

**Step 1 - Identify All Possible Control Technologies**

Based on the previously cited BACT Guideline, general control for $NO_X$ emissions from turbines include the following options:

1. Selective Catalytic Reduction (SCR) systems: consist of injecting ammonia upstream of a catalyst bed. The ideal operating temperature for a conventional SCR catalyst is 600 – 750 °F (titanium oxide). High temperature zeolite SCR catalysts have been developed that permit continuous SCR operation at temperatures as high as 1,050 °F. High temperature catalysts must be used when the SCR system needs to be placed upstream of the Heat Recovery Steam Generators (HRSG) or on a simple cycle turbine without heat recovery.

**3. Top-Down BACT Analysis (Continued):**

2. SCONO$_X$™: employs a precious metal catalyst and a NO$_X$ absorption/regeneration process step to convert CO and NO$_X$ into $CO_2$, $H_2O$, and $N_2$. The principle advantage of the SCONO$_X$™ technology over SCR is the elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO$_X$. SCONO$_X$™ has a maximum operating temperature of $\approx$ 700 °F

**NO$_X$ Emissions Control Technologies**

**a.** Selective Catalytic Reduction (SCR) systems
**b.** SCONO$_X$™

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their emission factor:

1. Selective Catalytic Reduction or SCONO$_X$™ or equal - 2.0 ppmv @ 15% $O_2$ (1-hour average, excluding startup and shutdown)
2. Selective Catalytic Reduction or SCONO$_X$™ or equal - $\leq$ 2.5 ppmv @ 15% $O_2$ (1-hour average, excluding startup and shutdown)

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO$_X$ emissions of 2.0 ppmv @ 15% $O_2$ (1-hour average). This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmv @ 15% $O_2$ (1-hour average). The facility has proposed to use Dry Low NO$_X$ combustors and a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmv @ 15% $O_2$ (1-hour average); therefore, BACT is satisfied.

**3. Top-Down BACT Analysis (Continued):**

**B. CO Top-Down BACT Analysis for Permits N-2246-3-0 and N-2246-4-0**

According to BACT guideline 3.4.2 (Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery), the following are possible controls for CO emissions from similar operations.

**Step 1 - Identify All Possible Control Technologies**

Based on the previously cited BACT Guideline, general control for CO emissions from turbines include the following options:

Achieved-in-practice BACT as 6.0 ppmv @ 15% $O_2$ with an oxidation catalyst and natural gas fuel.

Technologically feasible BACT as 4.0 ppmv @ 15% $O_2$ with an oxidation catalyst and natural gas fuel or LPG.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their emission factor:

1. 4.0 ppmv @ 15% $O_2$ with an oxidation catalyst or equal
2. 6.0 ppmv @ 15% $O_2$ with an oxidation catalyst or equal

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of an oxidation catalyst with CO emissions of 4.0 ppmv @ 15% $O_2$. This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of an oxidation catalyst with emissions of less than or equal to 4.0 ppmv @ 15% $O_2$. The facility has proposed to use an oxidation catalyst with emissions of less than or equal to 4.0 ppmv @ 15% $O_2$; therefore, BACT is satisfied.

**3. Top-Down BACT Analysis (Continued):**

**C. VOC Top-Down BACT Analysis for Permits N-2246-3-0 and N-2246-4-0**

According to BACT guideline 3.4.2 (Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery), the following are possible controls for VOC emissions from similar operations.

**Step 1 - <u>Identify All Possible Control Technologies</u>**

General control for VOC emissions include the following options:

**a.** 1.5 ppmvd @ 15% $O_2$.
**b.** 2.0 ppmvd @ 15% $O_2$.

**Step 2 - <u>Eliminate Technologically Infeasible Options</u>**

All control options listed in step 1 are technologically feasible.

**Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>**

1. 1.5 ppmv VOC @ 15% $O_2$
2. 2.0 ppmv VOC @ 15% $O_2$

**Step 4 - <u>Cost Effectiveness Analysis</u>**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmv @ 15% $O_2$. This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

**Step 5 - <u>Select BACT</u>**

BACT for the emission unit is determined to be VOC emissions of less than or equal to 1.5 ppmv @ 15% $O_2$. The facility has proposed VOC emissions of less than or equal to 1.4 ppmv @ 15% $O_2$; therefore, BACT is satisfied.

**D. $PM_{10}$ Top-Down BACT Analysis for Permits N-2246-3-0 and N-2246-4-0**

According to BACT guideline 3.4.2 (Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery), the following are possible controls for $PM_{10}$ emissions from similar operations.

**3. Top-Down BACT Analysis (Continued):**

**Step 1 - Identify All Possible Control Technologies**

**General control for $PM_{10}$ emissions include the following options:**

**a.** Air inlet filter, lube oil vent coalescer, and natural gas or equal

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Air inlet filter, lube oil vent coalescer, and natural gas.

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air inlet cooler/filter, lube oil vent coalescer, and natural gas fuel. This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of an air inlet cooler/filter, lube oil vent coalescer, and natural gas fuel. The facility has proposed to use an air inlet cooler/filter, lube oil vent coalescer, and natural gas fuel; therefore, BACT is satisfied.

**E. $SO_X$ Top-Down BACT Analysis for Permits N-2246-3-0 and N-2246-4-0**

According to BACT guideline 3.4.2 (Gas Fired Turbine ≥ to 50 MW, Uniform Load, with Heat Recovery), the following are possible controls for $SO_X$ emissions from similar operations.

**Step 1 - Identify All Possible Control Technologies**

General control for $SO_X$ emissions include the following options:

**a.** PUC regulated natural gas fuel.
**b.** Non-PUC regulated natural gas fuel with ≤ 0.75 gr-S/100 scf or equal.

**3. Top-Down BACT Analysis (Continued):**

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Non-PUC regulated natural gas fuel (≤ 0.75 gr-S/100 scf).
2. PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

**Step 4 - Cost Effectiveness Analysis**

The facility has proposed to use utility grade natural gas with a sulfur content of less than or equal to 0.36 grains per 100 scf. Since this is the most effective control option, a cost effectiveness analysis is not required.

**Step 5 - Select BACT**

The applicant has proposed to use PUC quality natural gas with a sulfur content of less than or equal to 0.36 grains per 100 scf as the $SO_X$ control technology. Therefore, BACT for this class of source is satisfied.

# ATTACHMENT G

## *TOP DOWN BACT ANALYSIS (N-2246-5-0)*

**1. BACT Applicability:**

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, or $SO_X$. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

As seen in Section VII.A.1 of this evaluation, the applicant is proposing to install a new emissions unit with PEs greater than 2 lb/day for $PM_{10}$. BACT is triggered for the $PM_{10}$ criteria pollutant since the PE is greater than 2 lbs/day.

**2. BACT Guidance:**

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. BACT Guideline 8.3.10, which appears in Attachment C of this report, covers cooling towers.

**3. Top-Down BACT Analysis:**

**A. $PM_{10}$ Top-Down BACT Analysis for Permit (C-3959-4-0):**

$PM_{10}$ emissions are due to the cooling water drift from the cooling tower. The cooling water contains total dissolved solids (TDS). As the cooling water drift evaporates, the solids remain as $PM_{10}$.

**Step 1 - Identify All Possible $PM_{10}$ Control Technologies**

The SJVUAPCD BACT Clearinghouse identifies technologically feasible BACT for this cooling tower as a Cellular type drift eliminator. There are no achieved-in-practice BACT technologies listed.

**Step 2 - Eliminate Technologically Infeasible Options**

There are no technologically infeasible options listed.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

Cellular type drift eliminator

**Step 4 - Cost Effectiveness Analysis**

The applicant has proposed a high efficiency drift eliminator with a drift rate of 0.0005%. This is at least as efficient as the most effective control technology listed above. Therefore, a cost effectiveness analysis is not required.

**3. Top-Down BACT Analysis (Continued):**

**Step 5 - Select BACT**

BACT for $PM_{10}$ emissions for this cooling tower is a high efficiency drift eliminator with a drift rate of 0.0005%. Therefore, BACT for this class of source is satisfied.

# ATTACHMENT H

## *TOP DOWN BACT ANALYSIS (N-2246-6-0)*

**1. BACT Applicability:**

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, or $SO_X$. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

As seen in Section VIII.A.1 of this evaluation, the applicant is proposing to install a new emissions unit with PEs greater than 2 lb/day for $NO_X$, CO, VOC, and $SO_X$. BACT is triggered for $NO_X$, CO, VOC, and $SO_X$ criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

**2. BACT Guidance:**

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. BACT Guideline 3.1.4, which appears in Attachment C of this report, covers diesel-fired emergency IC engines driving a fire pump.

**3. Top-Down BACT Analysis:**

**A. $NO_X$ Top-Down BACT Analysis for Permit N-2246-6-0**

Oxides of nitrogen ($NO_X$) are generated from the high temperature combustion of the diesel fuel. A majority of the $NO_X$ emissions are formed from the high temperature reaction of nitrogen and oxygen in the inlet air. The rest of the $NO_X$ emissions are formed from the reaction of fuel-bound nitrogen with oxygen in the inlet air.

**Step 1 - <u>Identify All Possible NOx Control Technologies</u>**

The SJVAPCD BACT Clearinghouse identifies achieved-in-practice BACT for this engine as certified $NO_X$ emissions of 6.9 g/hp-hr or less. No technologically feasible alternatives are listed.

**Step 2 - <u>Eliminate Technologically Infeasible Options</u>**

There are no technologically infeasible options listed.

**Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>**

Certified $NO_X$ emissions of 6.9 g/hp-hr or less.

**3. Top-Down BACT Analysis (Continued):**

**Step 4 - Cost Effective Analysis**

The only control technology alternative in the ranking list from Step 3 has been achieved in practice. Therefore, per SJVAPCD BACT policy, the cost effectiveness analysis is not required.

**Step 5 - Select BACT**

Therefore, BACT for $NO_X$ emissions is certified $NO_X$ emissions of less than 6.9 g/hp·hr. The proposed IC engine is certified with $NO_X$ emissions of 5.2 g/hp·hr, therefore BACT is satisfied.

**B. CO Top-Down BACT Analysis for Permit N-2246-6-0**

Carbon monoxide (CO) emissions are generated from the incomplete combustion of the diesel fuel.

**Step 1 - Identify All Possible CO Control Technologies**

The SJVAPCD BACT Clearinghouse identifies technologically feasible BACT for this engine as a non-selective catalytic reduction system. No achieved-in-practice BACT is listed.

**Step 2 - Eliminate Technologically Infeasible Options**

There are no technologically infeasible options listed.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

Non-selective catalytic reduction (60% CO control from Emission Control Technology for Stationary Internal Combustion Engines, Manufacturers of Emission Controls Association, October 1995).

**Step 4 - Cost Effectiveness Analysis**

A cost effectiveness analysis is performed for the highest control efficiency technology.

Assumptions:

- The emergency engine operates 100 hours per year for non-emergency purposes
- CO emission rate (AP-42, uncontrolled) - [3.03 g/hp-hr (for engines ≤ 600 bhp), or 2.4 g/hp-hr (for engines > 600 bhp)]
- Cost of non-selective catalytic reduction (CO catalyst) for diesel IC engines is $10-$20 per horsepower (from Emission Control Technology for Stationary Internal Combustion Engines, Manufacturers of Emission Controls Association, October 1995). Annualized cost using an interest rate of 10% and a life of 10 years is $1.63/hp-yr.

**3. Top-Down BACT Analysis (Continued):**

Annual Cost:

Using a conservative control system cost of $10 per horsepower hour, the annual cost is the following:

Annual Cost = 300 hp × $1.63/hp-year = $489/year

CO Emission Reductions:

CO Emission Reduction = 300 hp × 3.03 g/hp-hr × 0.6 × 1 lb/453.6 g × 100 hr/yr × 1 ton/2,000 lb
= 0.060 ton/year

Cost Effectiveness:

Since this option results in the control of more than one pollutant, a Multi-Pollutant Cost Effectiveness Threshold (MCET) must be calculated pursuant to section X.A.5 of District BACT Policy (APR 1305). If the total annual cost of the control technology is greater than the MCET, the control technology or equipment under review cannot be required as BACT.

A non-selective catalytic reduction system results in reductions of CO and VOC emissions. Therefore, the MCET for this operation can be calculated using the following formula:

MCET = [CO Emission Reduction (tons/year) × CO Cost Effective Threshold ($/ton)] + [VOC Emission Reduction (tons/year) × VOC Cost Effective Threshold ($/ton)]

As shown above the CO emissions reduction is 0.06 tons/year and as shown below the VOC emissions reduction is 0.022 tons/year. Therefore:

MCET = [0.06 tons/year × $300/ton] + [0.022 tons/yr × $5,000/ton]
= $128/year

As shown above, the total cost of a non-selective catalytic reduction system is $489/year. The cost of CO and VOC emission reduction utilizing a non-selective reduction system is greater than the $128/year multi-pollutant cost effectiveness threshold calculated above. Therefore, the control technology is not cost effective for this class and category of source.

**Step 5 - <u>Select BACT</u>**

Therefore, there are no additional control requirements for BACT for CO emissions for the diesel-fired emergency IC engine.

**3. Top-Down BACT Analysis (Continued):**

**C. VOC Top-Down BACT Analysis for Permit N-2246-6-0**

Volatile organic compounds result from the incomplete combustion of diesel fuel and are emitted from the crankcase of the engine as a result of piston ring blow-by.

**Step 1 - Identify All Possible VOC Control Technologies**

The SJVUAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved-in-practice BACT as positive crankcase ventilation (PCV) unless it voids the Underwriters Laboratories (UL) certification.

Catalytic oxidation is listed as a technologically feasible control technology.

**Step 2 - Eliminate Technologically Infeasible Options**

There are no technologically infeasible options listed.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Catalytic oxidation
2. Positive crankcase ventilation

**Step 4 - Cost Effectiveness Analysis**

A cost effectiveness analysis is performed for the highest control efficiency technology.

Assumptions:

- The emergency engine operates 100 hours per year for non-emergency purposes
- VOC emission rate (AP-42, uncontrolled) - [1.12 g/hp-hr (for engines ≤ 600 BHP), or 0.33 g/hp-hr (for engines > 600 BHP)]
- Cost of non-selective catalytic reduction (VOC catalyst) for diesel IC engines is $10-$20 per horsepower. Annualized cost using an interest rate of 10% and a life of 10 years is $1.63/hp-yr.

Annual Cost:

Using a conservative control system cost of $10 per horsepower hour, the annual cost is the following:

Annual Cost = 300 hp × $1.63/hp-year = $489/year

**3. Top-Down BACT Analysis (Continued):**

VOC Emission Reductions:

VOC Emission Reduction = 300 hp × 1.12 g/hp-hr × 0.6 × 1 lb/453.6 g × 100 hr/yr × 1 ton/2,000 lb
= 0.022 ton/year

Cost Effectiveness:

As shown in Step 4 of the Top-Down BACT analysis for CO emissions above, the MCET for a non-selective catalytic reduction system for this engine is $128/year.

As shown above, the total cost of a non-selective catalytic reduction system is $489/year. The cost of CO and VOC emission reduction utilizing a non-selective reduction system is greater than the $128/year multi-pollutant cost effectiveness threshold calculated above. Therefore, the control technology is not cost effective for this class and category of source.

The only remaining control technology alternative in the ranking list from Step 3 has been achieved in practice.

Positive crankcase ventilation (unless voids UL certification)

**Step 5 - Select BACT**

BACT for VOC emissions for this engine is a PCV system (unless voids UL certification). The proposed engine is not equipped with a PCV system, and the installation of a PCV will void the UL certification; therefore, BACT is satisfied with no additional control requirements.

**D. $SO_X$ Top-Down BACT Analysis for Permit N-2246-6-0**

Oxides of sulfur ($SO_X$) emissions occur from the combustion of the sulfur which is present in the diesel fuel.

**Step 1 - Identify All Possible SOx Control Technologies**

The SJVAPCD BACT Clearinghouse Guideline identifies achieved-in-practice BACT for this engine as low-sulfur fuel (0.05% by weight) or very low-sulfur fuel (0.0015% by weight) where available.

**Step 2 - Eliminate Technologically Infeasible Options**

There are no technologically feasible options.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

Low-sulfur fuel or very low-sulfur fuel

**3. Top-Down BACT Analysis (Continued):**

**Step 4 - <u>Cost Effectiveness Analysis</u>**

The only control technology alternative in the ranking list from Step 3 has been achieved in practice. Therefore, per SJVAPCD BACT policy, the cost effectiveness analysis is not required.

**Step 5 - <u>Select BACT</u>**

BACT for $SO_X$ emissions for this engine is the use of fuel with a sulfur content of 0.05% or 0.0015% where available.

# ATTACHMENT I

## *Ambient Air Quality Analysis*

# ATTACHMENT J

## *Compliance Certification*